S T A T E O F M I C H I G A N

BEFORE THE MICHIGAN PUBLIC SERVICE COMMISSION

* * * * *

In the matter, on the Commission's own motion Establishing the method and avoided cost Calculation for **UPPER PENINSULA POWER COMPANY** to fully comply with the Public Utilities Regulatory Policy Act of 1978, 16 USC 2601 et seq.	)))))))	Case No. U-18094

NOTICE OF PROPOSAL FOR DECISION

The attached Proposal for Decision is being issued and served on all parties of record in the above matter on July 5, 2017.

Exceptions, if any, must be filed with the Michigan Public Service Commission, 7109 West Saginaw, Lansing, Michigan 48917, and served on all other parties of record on or before July 19, 2017, or within such further period as may be authorized for filing exceptions. If exceptions are filed, replies thereto may be filed on or before August 2, 2017. **The Commission has selected this case for participation in its Paperless Electronic Filings Program. No paper documents will be required to be filed in this case.**

At the expiration of the period for filing exceptions, an Order of the Commission will be issued in conformity with the attached Proposal for Decision and will become effective unless exceptions are filed seasonably or unless the Proposal for Decision is reviewed by action of the Commission. To be seasonably filed, exceptions must reach the Commission on or before the date they are due.

MICHIGAN ADMINISTRATIVE HEARING SYSTEM
For the Michigan Public Service Commission

Suzanne D. Sonneborn

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Suzanne D. Sonneborn
Administrative Law Judge

July 5, 2017
Lansing, Michigan

S T A T E O F M I C H I G A N

MICHIGAN ADMINISTRATIVE HEARING SYSTEM

FOR THE MICHIGAN PUBLIC SERVICE COMMISSION

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PROPOSAL FOR DECISION

I.

OVERVIEW AND HISTORY OF PROCEEDINGS

In 1978, Congress enacted the Public Utilities Regulatory Policy Act, (PURPA), in an attempt to encourage the development of renewable electric energy sources, including cogeneration, to increase America's energy independence as well as reduce its reliance on fossil fuels, and ultimately lead to a larger amount of dispersed generation.[1] Among other things, PURPA requires that electric utilities purchase energy and capacity from qualifying facilities (QFs) within their service territories and that the rates for such purchases shall: (i) be just and reasonable to the electric consumer of the electric utility and in the public interest; and (ii) not discriminate against qualifying cogeneration and small power production facilities.[2] PURPA further provides that the rates for the electric

[1] 16 USC 2601 *et seq*.
[2] 16 USC 824a-3.

utilities' purchases shall not exceed the incremental cost to the electric utility of alternative electric energy, generally referred to as the respective utility's avoided cost.[3]

On May 3, 2016, the Commission issued an order outlining the administrative steps that have been taken since the Commission opened an investigation (by order dated October 27, 2015 in Case No. U-17973) into the related subjects of the PURPA and the avoided cost amounts that a public utility is obligated to pay to certain Qualifying Facilities (QFs). In doing so, the Commission noted that "it had been over two decades since avoided cost rates were developed and that, in light of the significant changes in the energy landscape and the imminent expiration of many of the original PURPA contracts, it was an opportune time to undertake a comprehensive reexamination of PURPA, with a focus on identifying appropriate methods for establishing avoided costs."[4] The Commission further noted that, at its direction, a Technical Advisory Committee (TAC) comprised of Staff and representatives of electric utilities and cooperatives, QFs, small power producers, and distributed generation advocates (including the Environmental Law and Policy Center), held several meetings and culminated in Staff's issuance of a draft report to the TAC and, ultimately, a final report (PURPA Report).[5] The PURPA Report discussed the various methods for determining avoided costs and recommended establishing an initial administrative process focusing on the appropriate methodology to be used by the electric providers for establishing avoided costs pursuant to PURPA.[6]

[3] *Id*. See also 18 CFR 292.101(b)(6): "Avoided costs means the incremental costs to an electric utility of electric energy or capacity or both which, but for the purchase of qualifying facility or qualifying facilities, such utility would generate itself or purchase from another source."
[4] MPSC Case No. U-18089, *et al*, May 3, 2016 Order, p. 2.
[5] *Id;* see also Exhibit S-2, which contains a copy of the PURPA Report.
[6] *Id*., pp. 2-3.

Having agreed with Staff's recommended administrative process, the Commission directed Consumers Energy Company (Consumers), DTE Electric Company (DTE Electric), Alpena Power Company, Upper Peninsula Power Company (UPPCO), and Thumb Electric Cooperative to file, in their respective dockets, proposed avoided cost methodologies and costs by June 17, 2016, and that Indiana Michigan Power Company, Northern States Power Company, Wisconsin Public Service Corporation, and Wisconsin Electric Power Company do the same by June 30, 2016.[7] The Commission specifically directed UPPCO to provide separate avoided cost calculations using: (1) the hybrid proxy plant method proposed by Staff in the PURPA Report; (2) the transfer price method developed under 2008 PA 295; (3) another method, if any, that the Company wishes to propose; and (4) a proposed standard offer tariff, including applicable design capacity.[8]

Consistent with the Commission's May 3, 2016 order, UPPCO filed its application on June 17, 2016. Therein, UPPCO indicates it is a Michigan corporation engaged in the generation, purchase, distribution and sale of electric energy in the Upper Peninsula of Michigan, serving certain cities, villages, and townships located in the counties of Alger, Baraga, Delta, Houghton, Iron, Keweenaw, Marquette, Menominee, Ontonagon, and Schoolcraft. UPPCO further submits in its Application that the avoided costs methodologies and resulting purchase costs produced by the hybrid proxy plant method proposed in the PURPA Report and the transfer price method developed under 2008 PA 295 are not appropriate for measuring UPPCO's avoided costs. Instead, UPPCO

[7] *Id.*, pp. 3-4.
[8] *Id.*

maintains that the method selected by the Company, identified as the “Full Requirement Contract Methodology,” should be adopted for UPPCO.

On July 14, 2016, the Environmental Law and Policy Center (ELPC), the Ecology Center, the Solar Energy Industries Association, and Vote Solar (hereafter referred to collectively as ELPC) filed a timely petition to intervene in each of the nine providers’ Commission-initiated filings, including UPPCO’s Application. UPPCO opposed the petition with written objections filed on July 20, 2016. Oral argument on the petition was held at the July 21, 2016 prehearing conference, and this ALJ subsequently granted permissive intervention to the ELPC.

Pursuant to the consensus schedule established at the prehearing conference, UPPCO filed the direct testimony and exhibit of Aaron L. Wallin on October 28, 2016. On January 13, 2017, Staff filed the direct testimony and exhibits of Merideth A. Hadala, Julie K. Baldwin, and Jesse J. Harlow and the ELPC filed the direct testimony and exhibits of Douglas Jester, Karl R. Rabago, Adam Schumaker, and Rand Dueweke. On February 17, 2017, UPPCO and the ELPC filed the rebuttal testimony of Mr. Wallin and Mr. Jester, respectively.

At the March 7, 2017 evidentiary hearing, UPPCO entered the direct and rebuttal testimony of Mr. Wallin and Mr. Wallin sponsored Exhibit A-1. The ELPC entered the direct and rebuttal testimony of Mr. Jester, the direct testimony of Mr. Rabago, Mr. Schumaker, and Mr. Dueweke, and Exhibits ELP-1 through ELP-7. Staff entered the direct testimony of Ms. Hadala, Ms. Baldwin, and Mr. Harlow, along with Exhibits S-1 through S-5. The evidentiary record is contained in 217 pages of transcript and 13 exhibits.

UPPCO, Staff, and the ELPC filed initial briefs on April 18, 2017, and UPPCO and the ELPC filed reply briefs on May 2, 2017.

II.

BACKGROUND

This section sets forth the relevant PURPA background, definitions, and methodologies necessary for an analysis and determination of the appropriate avoided cost methodology for UPPCO.

A. PURPA

PURPA was enacted in 1978 at a time when the United States was in the midst of an oil crisis in an effort to increase energy independence through a diversification of the energy portfolio. As provided in the Act:

> "The purposes of this title are to encourage—
> (1) conservation of energy supplied by electric utilities
> (2) the optimization of the efficiency of use of facilities and resources by electric utilities; and
> (3) equitable rates to electric consumers."[9]

The purpose of PURPA, with regard to renewables, was to provide reasonable access to the grid by alleviating obstacles for all qualifying facilities (QFs), including eliminating certain specified legal hurdles.[10] The optimization of the efficiency of use of facilities and resources is encouraged through increasing alternative energy options, for instance, by repurposing hydro dams, employing biomass such as plant and animal

[9] 16 U.S.C. § 2611. See also, 2 TR 210.
[10] 2 TR 210-211.

waste, to supply clean energy, and through increasing conservation, such as decreasing line losses in distribution systems.[11]

PURPA prohibits utilities from: (1) refusing to interconnect with QFs, (2) refusing to sell power to QFs at non-discriminatory rates, and (3) not fairly compensating QFs for power sold back to the utility. PURPA further requires an "electric utility to offer to purchase electric energy from any qualifying cogeneration facility or qualifying small power production facility" at rates that are: "[j]ust and reasonable to the electric consumers of the electric utility and in the public interest," and does "not discriminate against qualifying cogenerators or qualifying small power producers."[12] However, no rule prescribed by the Federal Energy Regulatory Commission (FERC) under this section of PURPA "shall provide for a rate which exceeds the incremental cost to the electric utility of alternative electric energy."[13]

B. <u>PURPA Qualifying Facilities</u>

PURPA Qualifying Facilities (QFs) are defined as qualifying cogeneration facilities or qualifying small power production facilities that have a right to be served by, and sell to, the electric utility of their choosing at a cost that does not exceed "the incremental cost to the electric utility of alternative electric energy."[14]

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[11] 2 TR 211.
[12] PURPA § 210(b); 16 USC § 824a-3(b).
[13] *Id.*
[14] *Id.*

C. **"Must Purchase" Obligation**

An electric utility must purchase energy and capacity made available from a QF at that utility's avoided costs. This PURPA "must purchase" obligation applies to all energy and capacity made available for sale from a QF and applies to all electric utilities, unless FERC grants a waiver.[15]

D. **Avoided Costs**

FERC regulations require a utility to purchase electricity from QFs at rates equal to the utility's full avoided cost.[16] "Avoided costs" are defined as the:

> "Incremental costs to an electric utility of electric energy or capacity or both which, but for the purchase from the qualifying facility or qualifying facilities, such utility would generate itself or purchase from another source."[17]

> "Incremental costs" are further defined as:

> "[t]he cost to the electric utility of the electric energy which, but for the purchase from such cogenerator or small power producer, such utility would generate or purchase from another source."[18]

FERC divides avoided costs into its two components: energy or capacity. Energy costs are the variable costs associated with the production of electric energy (kilowatt-hours) and represent the cost of fuel and some operating and maintenance expenses. Capacity costs are the costs associated with providing the capability to deliver energy and primarily represent the capital costs of a utility's facilities. As noted by FERC, if a QF:

> [o]ffers energy or sufficient reliability and with sufficient legally enforceable guarantees of deliverability to permit the purchasing electric utility to avoid

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[15] 18 CFR § 292.303(a); 18 CFR § 292.309.
[16] 18 CFR § 292.304.
[17] 18 CFR § 292.101(b)(6).
[18] PURPA § 210(d); 16 USC § 824a-3(d).

> the need to construct a generating unit, to build a smaller, less expensive plant, or to reduce firm power purchases from another utility, then the rate for such a purchase will be based on the avoided capacity and energy costs.[19]

FERC regulations provide that the following factors "shall, to the extent practicable, be taken into account" when determining avoided costs:

> (1) The data provided pursuant to § 292.302(b), (c), or (d), including State review of any such data;
>
> (2) The availability of capacity or energy from a qualifying facility during the system daily and seasonal peak periods, including:
>
> (i) The ability of the utility to dispatch the qualifying facility;
>
> (ii) The expected or demonstrated reliability of the qualifying facility;
>
> (iii) The terms of any contract or other legally enforceable obligation, including the duration of the obligation, termination notice requirement and sanctions for non-compliance;
>
> (iv) The extent to which scheduled outages of the qualifying facility can be usefully coordinated with scheduled outages of the utility's facilities;
>
> (v) The usefulness of energy and capacity supplied from a qualifying facility during system emergencies, including its ability to separate its load from its generation;
>
> (vi) The individual and aggregate value of energy and capacity from qualifying facilities on the electric utility's system; and
>
> (vii) The smaller capacity increments and the shorter lead times available with additions of capacity from qualifying facilities; and
>
> (3) The relationship of the availability of energy or capacity from the qualifying facility as derived in paragraph (e)(2) of this section, to the ability of the electric utility to avoid costs, including the deferral of capacity additions and the reduction of fossil fuel use; and
>
> (4) The costs or savings resulting from variations in line losses from those that would have existed in the absence of purchases from a qualifying facility, if the purchasing electric utility generated an equivalent amount

[19] FERC Order 69, 45 Fed. Reg. 12214, 12226, February 25, 1980.

of energy itself or purchased an equivalent amount of electric energy or capacity.[20]

E. Avoided Cost Methodologies

Avoided costs are commonly determined by the following FERC-accepted methods and can result in a wide range of avoided costs: (i) Proxy Unit Method; (ii) Peaker Unit Method; (iii) Differential Revenue Requirement; (iii) IRP Based Avoided Cost Method; (iv) Market Based Pricing; and (v) Competitive Bidding.[21] In her direct testimony, Staff witness Merideth Hadala described each of these methodologies, as set forth below.[22]

1. Proxy Unit Method

The proxy unity method relies on selecting a proxy plan and then using the costs of that unit to determine avoided costs for capacity and energy. Michigan's initial PURPA cases used this method with a proxy coal plant. The proxy plant selected as the hypothetical generating unity includes all of the future build uncertainties.[23] This method, referred to in the PURPA report as a "Staff Transfer Price" method, is described there as follows:

> Staff has performed a similar calculation for purposes of Act 295 of 2008 (MCL 460.1001 et seq.) transfer price determination based on the levelized cost of a 400 MW proxy natural gas combined cycle (NGCC) plant.
>
> This cost is projected each year based on inflation rates, projections for materials and labor costs and natural gas price forecasts. An NGCC plant is assumed to be the most logical marginal plant. Since QFs would be offsetting the need for new capacity, some PURPA TAC participants argued that QFs should be compensated at this avoided cost rate.

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[20].18 CFR § 292.302(e).
[21] Exhibit S-2, p. 14, footnote 8, citing Carolyn Elefant presentation to NARUC, March 2014.
[22] A review of the various PURPA avoided costs methods may also be found in a report prepared by Carolyn Elefant, titled "Reviving PURPA's Purpose: The Limits of Existing State Avoided Cost Ratemaking Methodologies in Supporting Alternative Energy Development and A Path for Reform."
[23] 2 TR 213.

> Staff's transfer price schedule methodology is updated annually and covers the remaining time frame of the Act 295 renewable energy planning period (ending in 2029). Staff describes the transfer price schedules as representative of what a Michigan utility would pay had it obtained energy and capacity through a long term power purchase agreement for traditional fossil fuel electric generation.[24]

2. Peaker Unit Method

The peaker unit method uses a peaker plant instead of a proxy plant, with the peaker unit likely being a single cycle natural gas unit. Because a peaking unit is intended to have high on-peak availability, while an intermittent resource may not, the use of the peaking method may be problematic. However, this issue could be remedied by taking into account the on-peak availability of the proposed resource.[25]

3. Differential Revenue Requirement

This method makes use of the calculation of the revenue requirement, as is done in a general rate case, and analyzes the revenue requirement with and without a specific facility, resulting in a differential revenue requirement that is then collected/reimbursed over the life of the contract.[26]

4. IRP Based Avoided Cost Method

This method uses an integrated resource plan (IRP) to produce values for energy and capacity. IRPs often require the use of complex software to: (i) run simulations of the current electricity system; (ii) create forecasts for demand growth and generation

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[24] Exhibit S-2, pp. 14-15.
[25] *Id.*
[26] *Id.*

retirements; (iii) determine when capacity will be needed, based on supply and demand; and (iv) determine why type of generation is most beneficial to the system. IRPs can forecast the market prices and energy and capacity to be used to determine avoided costs. Although utilities often have the required software for an IRP analysis, state commissions and QFs may have to rely upon third parties for such an analysis.[27]

5. Market Based Pricing

Developments in markets for energy and capacity have led to market based avoided cost methodologies, a method particularly relevant in fully deregulated environments where all generation is reliant on the market for cost recovery.[28] The PURPA Report describes this method as follows:

> This methodology values the QF's energy at the Locational Marginal Price (LMP) calculated by the Midcontinent Independent System Operator (MISO) and capacity at the ISO capacity market price determined by the MISO Planning Reserve auction (PRA). …The capacity prices from these auctions represent the incremental cost of capacity, not the long-term cost that could be equivalent to the capacity added to a utility's system by a QF. The MISO PRA provides a balancing function and according to a MISO Staff Draft Proposal dated March 18, 2016 titled *Competitive Retail Solution*, the existing PRA was not designed to meet " …the need to maintain existing and/or invest in new resources necessary to assure resource adequacy in competitive retail areas that rely exclusively on markets.[29]

6. Competitive Bidding

This method relies upon a utility issuing a request for proposal (RFP) and using those results to determine a competitive price for energy and capacity. This process

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[27] 2 TR 213-214.
[28] 2 TR 214.
[29] Exhibit S-2, pp. 16-17. Footnote 16 (citing https://www.misoenergy.org/Library/Repository/Meeting%20Material/Stakeholder/CRSTT/Draft%20CR%20FCA%20Pr oposal%20CoreDesign.pdf) omitted. (Emphasis in original).

requires a sufficient number of qualified bidders, can be time-consuming, and often involves, among other things, expectations regarding bidder qualifications, access to capital, previous experience, and employee safety. QFs may either participate in the RFP process, or wait to see if the rates resulting from the process are acceptable.[30]

F. <u>Staff's Modified Proxy Plant Methodology</u>

Staff's Modified Proxy Plant Methodology was first presented in Staff's PURPA Report and has since been Staff's proposed method in the PURPA avoided cost cases of Consumers Energy Company and DTE Electric Company, Case Nos. U-18091 and U-18090, respectively, as well as in the instant case.[31] Staff witness Jesse Harlow described the methodology as follows:

> The methodology combines a combustion turbine proxy unit for capacity and market based pricing for energy. In addition, a component is included that represents the cheaper market energy cost that is attributable to a combined cycle natural gas plant when the capacity proxy used is a combustion turbine. Staff calls this component the fixed investment cost attributable to energy (ICE). It is Staff's belief that this method currently provides the most accurate valuation of the Company's avoided cost as it utilizes a market based approach and a proxy plant method for capacity that does not rely on the MISO capacity auctions that, for reasons stated below in my testimony, does not accurately value long term capacity and does not send appropriate market signals.[32]

III.

<u>POSITIONS OF THE PARTIES</u>

In the section that follows, this Proposal for Decision (PFD) will summarize the

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[30] 2 TR 214.
[31] Exhibit S-2, p. 17; Case Nos. U-18090 and U-18091.
[32] 2 TR 199-200.

parties' testimony and respective positions. Analysis of the parties' arguments and the related portions of the record, as well as suggestions for the Commission's resolution of the issues raised in this case, are presented in Section IV of this PFD.

A. <u>UPPCO</u>

Relying on the testimony of Mr. Wallin, UPPCO's Manager of Power Supply and Resource Planning, the Company proposes that its avoided costs be set on the cost to purchase energy and capacity from another source, a determination that Mr. Wallin maintains is recognized by the definition of avoided cost, which "does not specify that avoided cost can be determined only by the cost of a utility to generate itself."[33] Mr. Wallin testified that this recognition is significant "because the definition recognizes the unique circumstances of individual utilities and that utilities may obtain necessary energy and capacity in different ways in order to minimize energy and capacity costs while meeting its regulatory requirements."[34] He also noted that, "[d]epending on a number of factors including cost, a utility such as UPPCO may purchase energy and capacity if not purchasing from the QF rather than construct and own generating assets."[35] Mr. Wallin further explained the importance of this distinction:

> It is important so as to properly determine avoided cost for a specific utility based on the actual cost the utility could avoid by purchasing from a QF. For example, UPPCO is a small utility where constructing generating assets may not be the most cost effective method for UPPCO to fulfill its customers' energy and capacity needs. Staff's hybrid proxy method assumes that the capacity value attributed to a QF is based on the levelized cost of a 210 MW Natural Gas Combustion Turbine. UPPCO's coincident peak load for MISO planning purposes for the 2017/18 planning year is only 122.8 MWs, its

[33] 2 TR 28-29.
[34] 2 TR 29.
[35] *Id.*

> Planning Reserve Margin Requirement is estimated to be 134.9 MWs, while the estimated capacity value of its owned resources is 112 MWs. UPPCO will only need 22.9 MWs of additional capacity to meet its MISO resource adequacy requirements for the 2017/18 MISO planning year. The assumption that UPPCO would construct a generating facility significantly larger than the approximately 23 MWs needed to meet this requirement is illogical and unreasonable. Furthermore, constructing a generating unit of the size UPPCO would need will very likely not be cost competitive with market prices for the same volume of capacity. Under these circumstances, the avoided cost should be set on the cost to purchase energy and capacity from another source.[36]

Mr. Wallin acknowledged that Staff has identified the following three options for capacity payments to a QF: (i) at the full avoided cost capacity rate discounted for the Effective Load Carrying Capacity (ELCC) regardless of the utility capacity needs; (ii) at the full avoided cost capacity rate, discounted for the ELCC for intermittent resources, until the utility demonstrates to the Commission that capacity additions are not necessary for itself or its Local Resource Zone (LRZ); and (iii) regardless of utility capacity needs, at 75% of the avoided capacity rate determined by Staff's hypothetical hybrid proxy plant methodology discounted for the ELCC.[37]

Mr. Wallin further explained that the Company's initial filing proposed avoided cost methodologies and costs using Staff's first option, the hybrid proxy plant method, to estimate UPPCO's avoided cost of energy and an annualized capacity cost of $128,847/MW.[38] However, after the Company's initial filing, UPPCO successfully entered into a contract to purchase needed capacity through its 2019/2020 planning year, which contract "has a significant impact on the determination of UPPCO's avoided cost in this proceeding" – specifically, the contract provides for the purchase of capacity at a

[36] 2 TR 29-30.
[37] 2 TR 30.
[38] 2 TR 31.

price of $25,000/MW, $30,000/MW, and $36,000/MW for MISO Planning Years 2017/18, 2018/19, and 2019/20, respectively.[39] Because UPPCO has already purchased sufficient capacity to meet its requirements for the foreseeable future, Mr. Wallin testified that capacity costs should therefore not be a component of the avoided cost determination in this proceeding, otherwise UPPCO's customers would be "incurring unnecessary costs for excess capacity" that is not needed.[40] Regarding the MISO Planning Year 2020/20 and beyond, Mr. Wallin recommended that, should UPPCO need capacity to meet its resource adequacy requirements, the Company should only be required to pay for the lower of market cost to purchase capacity, or, the estimated avoided cost using a proxy plant methodology.[41] And, if UPPCO has already procured sufficient capacity to meet its requirements, Mr. Wallin further recommended that the Company not be required to pay the QF for its equivalent capacity value as doing so would be "subsidizing the QF at the expense of the ratepayer."[42]

Mr. Wallin described in detail the methodology he used to develop the avoided capacity costs of $128,847/MW per year submitted in UPPCO's initial filing, whilst cautioning that these prices, although supporting Staff's hybrid proxy plant methodology (Option 1), do not accurately represent UPPCO's avoided cost of capacity.[43] Mr. Wallin explained that these prices assume the capacity the QF would supplant would be the annualized fixed costs of a hypothetical conventional combustion turbine (CT), a unit for which UPPCO lacks the capacity needs, thus UPPCO would likely purchase any capacity

[39] 2 TR 31.
[40] 2 TR 31.
[41] 2 TR 31.
[42] *Id*.
[43] 2 TR 33-34.

needs from the market.[44] And, because UPPCO has already procured the capacity it needs to meet its MISO resource adequacy requirements for the next three years, Mr. Wallin explained that UPPCO replaced the result of the hypothetical proxy plant methodology with actual capacity prices for the 2017/18 through 2019/20 planning years and performed the same calculations to determine the avoided cost of capacity on a $/MWh basis.[45] According to Mr. Wallin, the resulting capacity rates are lower than the rates submitted in UPPCO's initial filing:

> The rates based on UPPCO's actual cost of capacity are significantly lower than the rates using Staff's hybrid proxy plant methodology, AC Option 1. The rate for a wind facility has declined from $6.304/MWh to approximately $1.50/MWh from 2017 through 2020. The rate for a solar facility has declined from $31.623/MWh to approximately $7.40/MWh from 2017 through 2020. The rate for a landfill gas facility has declined from $17.304/MWh to approximately $4.06/MWh from 2017 through 2020. The rate for a biomass facility has declined from $18.386/MWh to approximately $4.30/MWh from 2017 through 2020. The rate for a hydro facility 1 has declined from $24.514/MWh to approximately $5.75/MWh on average from 2017 through 2020.[46]

Mr. Wallin nonetheless maintains that the capacity component should be excluded from the avoided cost rates because UPPCO has purchased all needed capacity to meet its MISO resource adequacy requirements for the next three planning years.[47]

Regarding the energy payment options for QFs, as identified by Staff in its PURPA Report, Mr. Wallin testified that the first option – which provides for energy payments to the QF at the Locational Marginal Price (LMP) at the time of delivery – should be adopted for UPPCO because:

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[44] 2 TR 34.
[45] 2 TR 35.
[46] 2 TR 35-36.
[47] 2 TR 36.

> UPPCO is a MISO market participant and has unrestricted access to a robust and efficient energy market. If UPPCO needs to procure additional energy to meet its customer demand, UPPCO is able to purchase that energy from MISO at the prevailing LMP. UPPCO also delivers energy into the MISO market and is paid the prevailing LMP for the energy it delivers. It is UPPCO's position that allowing QFs to be paid based on a forecasted energy price does not accurately represent the actual 1 cost of energy at the time it is received from the QF. Comparably, the Commission does not allow UPPCO to recover its cost of purchased power based solely on estimates. UPPCO, through the PSCR reconciliation process, only pays the actual cost of the energy it procures. A QF should be treated no differently.[48]

Mr. Wallin also provided rebuttal testimony to both Staff and ELPC, which is discussed below in Section III.D.

B. <u>Staff</u>

Staff offered testimony and exhibits from three witnesses, Meredith A. Hadala, Jesse J. Harlow, and Julie K. Baldwin, all of whom work in the Commission's Electric Reliability Division and whose testimony collectively recommends that the Commission adopt a modified proxy unit method as it "combines a combustion turbine proxy unity for capacity and market based pricing for energy" that provides "the most accurate valuation of UPPCo's avoided cost using both the market based approach and the proxy unity method."[49]

In her testimony, Ms. Hadala provided an overview of PURPA and explained how equitable rate and avoided cost are established, including a discussion of each of the FERC-accepted methods for determining avoided cost.[50]

In his testimony, Mr. Harlow presented Staff's proposed modified proxy plan

[48] 2 TR 37-38.
[49] 2 TR 199.
[50] 2 TR 210-215.

methodology in lieu of UPPCO's proposed avoided cost methodology, characterizing Staff's method as "the most reasonable method for the Company to use as Staff believes its proposal combines the most appropriate components of the market and traditional proxy plant avoided cost calculations."[51] In doing so, Mr. Harlow noted that not only has the regulatory construct with respect to avoided cost changed since the existence of the Mid-Continent Independent System Operator (MISO), but Staff supports consistent application of methods and has proposed this same method in the avoided cost proceedings of Consumers Energy Company and DTE Electric Company, Case Nos. U-18091 and U-18091, respectively.[52] Mr. Harlow described Staff's proposed method as follows:

> Staff first presented this methodology in Staff's PURPA Technical Advisory Committee *Report on the Continued Appropriateness of the Commission's Implementation of PURPA* on April 8, 2016 (Attached as EXHIBIT S-2 (JJH-1)). The methodology combines a combustion turbine proxy unit for capacity and market based pricing for energy. In addition, a component is included that represents the cheaper market energy cost that is attributable to a combined cycle natural gas plant when the capacity proxy used is a combustion turbine. Staff calls this component the fixed investment cost attributable to energy (ICE). It is Staff's belief that this method currently provides the most accurate valuation of the Company's avoided cost as it utilizes a market based approach and a proxy plant method for capacity that does not rely on the MISO capacity auctions that, for reasons stated below in my testimony, does not accurately value long term capacity and does not send appropriate market signals.[53]

Mr. Harlow further testified that MISO's Planning Reserve Auction (PRA) was established for balancing functions to make up small zonal resource credit shortfalls and is not intended to support resource investment decisions.[54] As a result, "the PRA does not

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[51] 2 TR 196.
[52] 2 TR 196-197.
[53] 2 TR 199-200 (Emphasis in original); Exhibit S-2.
[54] 2 TR 200.

function as a 'true' market as it will likely never produce price signals that prompt capacity build-outs and the utility itself would never utilize the PRA as the sole source of capacity cost recovery for long-lived generation plant investments absent traditional regulated cost recovery."[55]

According to Mr. Harlow, Staff's proposed capacity model uses a natural gas CT value that better aligns with the actual capacity value provided by a QF through a long-term contract, and also differs from the model presented in Staff's TAC Report as follows:

> Staff's capacity model attached as Exhibit S-3 (JJH-2) uses the inputs from the DTE Electric Company's filing in U-18091 for a NGCC and then applies a ratio comparing a NGCC and CT based on Consumers Energy Company's confidential avoided cost filing in Case No. U-18090. This was the most comprehensive data that Staff had available as the Company did not provide this data in its filing. Staff recommends that the Company adopt Staff's model and update it with inputs specific to and based on its filings with the Commission going forward.[56]

Regarding the energy component of Staff's proposed method, of the three options suggested by Staff in the TAC Report, Staff recommends the third option for UPPCO – specifically, that the Company pay an energy price based on the forecasted variable cost of a natural gas combined cycle plant (NGCC).[57] Mr. Harlow provided Staff's rationale for this recommendation:

> Staff utilized the variable cost component of the model used for calculating transfer prices to determine the avoided energy price for option three. Staff contends that this is representative of what a Michigan electric provider would pay had it obtained the energy through a long term power purchase agreement. Staff determined that the levelized variable cost of a NGCC plant would likely be analogous to the energy market price mentioned above. Starting with the U.S. Energy Information Administration's (EIA)

[55] 2 TR 201.
[56] 2 TR 202; Exhibit S-3.
[57] 2 TR 204; Exhibit S-4.

> levelized cost estimate for an advanced natural gas combined cycle facility, Staff built a trend line from that cost estimate to follow the value of energy.[58]

Staff further recommends that, in addition to the inclusion of either the LMP, LMP forecast or the NGCC operating cost forecast options, the energy payments to the QF should include a fixed investment cost attributable to energy (ICE).[59] Mr. Harlow explained the rationale behind this recommendation:

> The rationale is that in order to realize a cheaper energy price on the market, additional capital costs to build an NGCC are incurred over and above the cost to build a CT, as a CT would generally be built to provide cheap capacity while an NGCC would be built to provide cheap energy.[60]

Ms. Baldwin testified that Staff recommends that the Commission review UPPCO's avoided cost data and calculations on a biennial basis, consistent with Section 18 CFR 292.302(b) of the PURPA regulations.[61] And, recognizing that the Company has requested approval for a Standard Offer tariff available to WFs with a design capacity of 100kW or less, Staff nonetheless recommends that QFs larger than 100kW have the option to take service under the rates and terms of the Standard Offer tariff.[62] Ms. Baldwin explained:

> The Company has requested approval for a Standard Offer tariff available to QFs with a design capacity of 100 kW or less. QFs larger than 100 kW would negotiate with the utility to obtain a contract.
>
> PURPA requires the Standard Offer to be available to QFs with a design capacity of 100 kW and less. The Company's tariff meets that requirement. However, PURPA provides that the Standard Offer may be available to QF's with a design capacity of more than 100 kW up to 20 MW. QFs not taking service under the Standard Offer must negotiate a contract with the utility. A 100 kW QF is quite small and a utility customer installing a project up to

[58] 2 TR 204.
[59] 2 TR 205.
[60] 2 TR 205.
[61] 2 TR 183.
[62] 2 TR 184.

> 100 kW in design capacity may find it more economically favorable to take service under the modified net metering program (if available, subject to the limitations of the net metering program) and may not opt for the Standard Offer tariff. If larger QFs are permitted to take advantage of the Standard Offer tariff, assuming the avoided cost is appropriately set, customers will not be negatively impacted when the contracting and transaction costs for both the utility and the QF are reduced through the use of the Standard Offer tariff.[63]

Staff further recommends the following three revisions to UPPCO's Standard Offer tariff, set forth in Exhibit A-1: (i) the Standard Offer tariff QF size cap be set in the range of 1 MW to 5 MW according to the capacity need of the utility during the succeeding year and the PURPA 10-year planning horizon; (ii) the Standard Offer contract term be set at 5, 10 or 15 years, at the QF's option; and (iii) the Standard Offer rates on the tariff be provided based on the 5, 10 and 15 year forecasts of UPPCO's avoided costs.[64]

Ms. Baldwin explained Staff's first recommended revision to UPPCO's Standard Offer tariff as follows:

> Staff recommends that the Commission consider the capacity needs of the utility during each annual avoided cost update filing to set the Standard Offer size cap. Factors the Commission may want to consider are how much capacity the utility needs in the next year and how much the utility needs during the entire 10-year PURPA capacity planning horizon. Capacity from the renewal of existing PURPA contracts should be appropriately figured into the Company's capacity position also. If a utility needs a significant amount of capacity during the succeeding year, then Staff recommends the QF Standard Offer size cap be set at 1 the higher end of the range and closer or equal to 5 MW. If the capacity need is further out in the PURPA 10-year capacity planning horizon, then a smaller Standard Offer size cap set at 1 MW may cause QF capacity to build more slowly. For a utility like UPPCO with no capacity needs until at least until 2021, Staff recommends a 1 MW Standard Offer QF size cap. The Company's capacity needs for the latter part of the 10-year PURPA planning horizon are unknown.[65]

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[63] 2 TR 183-184.
[64] 2 TR 182.
[65] 2 TR 184-185.

Regarding Staff's second recommended revision to UPPCO's Standard Offer tariff, Ms. Baldwin explained that allowing a QF to select a specified contract term not only provides certainty and may be a factor leading to a feasible QF project, but such an option may ultimately benefit customers because "[u]nder a 5, 10 or 15 year contract, the QF would receive certainty of capacity and energy payments (as long as the "As Available" energy option was not selected)."[66] Ms. Baldwin also described the three energy rate options included on the Standard Offer Tariff as being: As Available Rate, LMP Energy Rate Forecast and Proxy Plant Variable Rate Forecast.[67] Moreover, Staff has proposed a capacity rate that is equal to the capacity costs of a natural gas combustion turbine plant.[68] Finally, Staff recommends the following additional modifications to the tariff: (i) the language regarding customers' right to appeal to the PSCW be replaced with the Michigan Public Service Commission; (ii) renewable energy credit (REC) ownership be transferred to UPPCO when QFs take service under the Standard Offer tariff; and (iii) UPPCO request *ex parte* processing when filing contracts based upon the Standard Offer tariff for Commission approval.[69]

C. <u>ELPC</u>

As noted earlier, ELPC offered the testimony of four witnesses, all of whom collectively agree with Staff's recommendations with some slight modifications to the methodology.[70]

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[66] 2 TR 186-187.
[67] 2 TR 187 Exhibits S-4 and S-5.
[68] 2 TR 188; Exhibit S-3.
[69] 2 TR 188-189.
[70] ELPC's Initial Brief, p. 2.

Mr. Jester, a principal at 5 Lakes Energy LLC, testified that UPPCO's avoided cost proposal fails to satisfy the provisions of Part 210(b) of PURPA because the proposed rates "are unduly discriminatory 'against qualifying cogenerators or qualifying small power producers'" resulting in less development of QFs than would occur under nondiscriminatory rates that reflect full avoided costs and, ultimately, costs are not just and reasonable to electric customers.[71] Mr. Jester testified that UPPCO's proposal is also insufficient because:

> Those qualifying facilities that would be developed under the proper, nondiscriminatory avoided cost would either (1) not combust fuel that produces air pollution and related health and environmental harms, or (2) would not use fossil fuels, and hence would not produce as much greenhouse gas emissions as would likely be produced by Upper Peninsula Power Company (or by another utility in fulfillment of a wholesale power supply agreement with Upper Peninsula Power Company) in producing alternative electric energy, or (3) would use fossil fuels more efficiently than would likely be done by Upper Peninsula Power Company (or by its wholesale provider) in producing alternative electric energy. Reduced pollution and downward pressure on fossil fuel prices are in the public interest, so rates that discriminate against qualifying facilities are not in the public interest, in addition to violating federal law.[72]

Mr. Jester instead recommended that the Commission determine UPPCO's avoided costs in two phases, the first of which would extend until the end of UPPCO's current power supply contracts on May 31, 2020 and be based on the terms of those contracts as well as account for all potential avoided costs, unlike the methodology proposed by UPPCO.[73] And, pursuant to Mr. Jester's recommendation, the second

[71] 2 TR 75-76; see also 2 TR 107-108.
[72] 2 TR 76.
[73] 2 TR 82.

phase would commence on June 1, 2020 and be based on the PURPA TAC Report prepared by Staff (ie. the proxy plant method) with the following five exceptions:[74]

> First, pursuant to 2016 PA 342 Upper Peninsula Power Company is obligated to meet a 10% renewable energy standard in 2017 and 2018, 12.5% renewable energy standard in 2019 and 2020, and 15% renewable energy standard in 2021 and thereafter. Upper Peninsula Power Company is also obligated to pursue a 35% clean energy goal, combining energy waste reduction and renewable generation, in 2025 and thereafter. Upper Peninsula Power Company is required by 2016 PA 342 to offer "customer requested renewable energy". To the extent that Upper Peninsula Power Company's customers request such power, and a qualifying facility provides the means for Upper Peninsula Power Company to comply with this requirement, the avoided costs attributable to the qualifying facility must include any costs Upper Peninsula Power Company would otherwise incur to meet that requirement. To the extent that a qualifying facility contributes to Upper Peninsula Power Company's compliance with any of these requirements and Upper Peninsula Power Company avoids costs of compliance by some other means, the avoided costs for the qualifying facility must include such costs. Since overall cost minimization requires that a qualifying facility be used to satisfy Upper Peninsula Power Company's most costly requirement to which the qualifying facility contributes, the avoided cost in 2020 and thereafter should be the largest of the avoided costs of meeting one of these requirements or of avoided costs of general service as determined by the proxy plant method recommended in the PURPA Technical Advisory Committee Report.
>
> Second, when a qualifying facility will be interconnected at subtransmission, primary distribution, or secondary distribution and its output is reasonably expected to serve load on the same grid segment without flowing onto the transmission grid, then the Commission should recognize reduced losses in both capacity and energy delivery. In addition, the Commission should include in avoided costs any reduction of payments by Upper Peninsula Power Company to MISO or other parties for transmission and other services avoided by virtue of the operation of the qualifying facility on Upper Peninsula Power Company's distribution grid.
>
> Third, in computing the avoided cost of capacity, the Commission should use the avoided cost per unit of useful capacity in the proxy plant and not the avoided cost per unit of nameplate capacity.

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[74] 2 TR 79.

> Fourth, the Commission must allow for the case-by-case determination of avoided costs of transmission and distribution capacity and any other cost categories not included in the Commission's basic methods.
>
> Finally, the Commission should include the avoided cost of compliance with carbon regulation in its calculation of avoided energy costs, to the extent that utilities are incurring real costs in response to projected future compliance requirements.[75]

Mr. Jester also explained why he recommends the Commission adopt the TAC Report recommendation to use the proxy plant method to determine avoided costs:

> The Proxy Plant Methodology is most consistent with the way in which the Commission regulates Michigan utilities. The Commission decides whether a utility's investments and other expenditures are prudent and reasonable and then authorizes recovery of those costs through cost-of-service regulation. While the Commission doesn't ignore the MISO market, it does not authorize cost recovery for new generation resources based on whether or not the plant would be profitable in the MISO market. It determines whether the plant contributes to the welfare of the Michigan utility's customers and, for larger investments, that the investment is the most prudent and reasonable available option. The Proxy Plant Methodology reflects this decision-making process.
>
> PURPA recognizes that the Commission operates within the context of timing and initiative driven by the utility, which may foreclose opportunities for the development of alternative resources that are favored by broad public policy, and gives the Commission the opportunity to look ahead to the decision they would likely face under utility initiative and to establish a framework for PURPA qualifying facilities to emerge as alternatives.[76]

Mr. Jester envisioned two options should the utility not generate its own power: (i) use the avoided cost of the utility that generates the power for which the supplying utility contracts; or (ii) the qualifying facility would contract directly with the generating utility.[77]

He also recommended the Commission adopt Staff's recommendation in the TAC Report that a combined cycle natural gas plant be used as the proxy plant for

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[75] 2 TR 83-85.
[76] 2 TR 90.
[77] *Id*.

determination of PURPA avoided costs because such a plant is the most likely utility-scale generation to be built.[78] Likewise, the use of the cost of a natural gas combustion turbine to determine avoided cost of capacity is recommended, according to Mr. Jester, because these turbines are “the resource most commonly used for this purpose because they have the lowest capital carrying cost per unit of unforced firm capacity.”[79]

Mr. Jester acknowledged that UPPCO’s capacity requirements are currently largely met by existing power supply contracts, which is why Mr. Jester has recommended separate avoided cost determinations during the period until and after the end of those contracts.[80] Mr. Jester submitted, however, that if the Commission were to allow UPPCO to use its current contracts to assume a continuation of this practice after a contract ends, doing so would unduly discriminate against potential PURPA qualifying facilities by allowing UPPCO to lock-in certain costs and rendering it contractually impossible for an avoidance of those costs via any subsequent offer from a qualifying facility.[81]

Further recognizing that Staff’s proposed methodology does not address carbon emissions, Mr. Jester nonetheless recommended the Commission include the cost of compliance with carbon regulations in its calculation of avoided costs because it is likely that UPPCO is “taking into account the likelihood of carbon regulation in its planning now, leading the company to incur real costs today that would be avoided through purchases from non-carbon emitting qualifying facilities.[82] Mr. Jester described in detail how carbon compliance costs can be quantified and included in avoided costs, whether utilities are

[78] 2 TR 91.
[79] *Id*.
[80] 2 TR 99.
[81] 2 TR 99-100.
[82] 2 TR 102.

today incurring real costs of compliance, and why the Commission should use a forecast commissioned by the Michigan Agency for Energy and prepared by Synapse Energy Economics for Clean Power Plan Compliance.[83]

Mr. Jester also disagreed with UPPCO's proposal that contract terms for PURPA qualifying facilities be set through negotiation, testifying that the Commission should instead require "a standard offer contract of sufficient duration to support financing for investment in a qualifying facility, just as it provides certainty to [UPPCO] that its reasonable and prudent investments will be recovered with a reasonable return on capital."[84] Noting that FERC rules require UPPCO to offer standard contracts for qualifying facilities with capacity less than 100 kW but allow the Commission to require such contracts for facilities of greater capacity, Mr. Jester maintained that the Commission should therefore require UPPCO to offer standard contracts at least up to 5 MW capacity as recommended by Staff in the PURPA TAC Report.[85]

Mr. Jester also provided rebuttal testimony in response to the testimony of Staff, which is discussed below in Section III.D.

Mr. Rabago, a principal of New-York based Rabago Energy LLC, provided testimony on the background and purpose of PURPA, Michigan's role in implementing PURPA, the importance of a comprehensive, non-discriminatory approach to avoided costs, the full avoided cost methods, as well as deficiencies in UPPCO's proposal and his

[83] 2 TR 102-105.
[84] 2 TR 108.
[85] 2 TR 109-110.

recommended support for Staff's proposed methodology.[86] Regarding the latter, Mr. Rabago testified:

> I support a capacity payment based on the cost of a natural gas combustion turbine discounted by Effective Load Carrying Capability ("ELCC") for intermittent resources. This capacity payment should be made regardless of the utilities' immediate capacity needs because the qualifying facility capacity allows the utility to defer future capacity over the planning horizon. I support an energy payment based on the forecasted variable costs of an NGCC as calculated in the Staff Transfer Price, with the addition of a fixed investment cost attributable to energy. ("ICE").[87]

Such a capacity payment method, Mr. Rabago testified, is consistent with avoided costs and nondiscriminatory rates, as required by PURPA.[88] Likewise, the ICE adjustment to Staff's proposed energy payment is an appropriate reflection of UPPCO's capacity investment cost obligation associated with a NGCC but for the purchase of energy from a qualifying facility.[89] Mr. Rabago also recommended that the Commission require consideration of the following types of avoided costs: avoided transmission costs; line loss mitigation; hedging value; avoided emissions and environmental compliance costs; and avoided costs revealed through a comprehensive value of solar analysis.[90] He also supports Staff's proposal to extend the standard offer rate to projects of 5 MW in size, and ideally to 20 MW in size, as well as Staff's process recommendations.[91]

Mr. Rabago further recommended the Commission adopt the following three measures: (i) a policy of technology-specific evaluation of avoided costs; (ii) a policy supporting evaluation and quantification of full avoided costs for resources connected

[86] 2 TR 126-132.
[87] 2 TR 133.
[88] Id.
[89] 2 TR 134.
[90] 2 TR 135.
[91] 2 TR 135; see also ELPC's April 1, 2016 Comments, contained in Exhibit ELP-4.

both at the transmission level and in the distribution grid; and (iii) an overarching policy against undue discrimination against renewable energy and high efficiency qualifying facilities by utilities.[92] He emphasized that a comprehensive, non-discriminatory approach to avoided costs is “essential to realizing the vision of PURPA for securing the benefits that an efficient, rational, and competitive market would provide in ensuring that utilities cannot extract monopoly rents from their self-build generation options.”[93] Moreover, such an approach “protects customers and the public interest by ensuring that non-utility generation is developed where it is economically beneficial to do so.”[94]

Noting that the Commission has broad authority to account for all of the costs avoided when electricity from a qualifying facility displaces a unit of system electricity, Mr. Rabago testified that environmental costs can also be considered if such costs are “part of the utility’s cost of doing business to the extent those costs would be avoided by the purchase from the qualifying facility.”[95] However, short-run prices and short-term contracts should not be used to set avoided cost rates, according to Mr. Rabago, because doing so would unfairly discriminate against qualifying facilities by using time horizons and valuations that the utility does not assign to its self-build options.[96] Whereas, costs associated with transmission, distribution, delivery, and system operation should be included because, whether purchased self-generated or purchased from the market, such costs are real costs that are or can be avoided when distributed generation operates.[97]

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[92] 2 TR 136.
[93] 2 TR 138.
[94] *Id*.
[95] 2 TR 141-142.
[96] 2 TR 143.
[97] 2 TR 144.

Finally, Mr. Rabago recommended that the Commission modify Staff's proposed methodology regarding avoided costs for distributed generation to reflect the full range of costs that are avoided by distributed generation resources, including but not limited to transmission costs, line losses, as well as require UPPCO to use that methodology in designing proposed avoided cost rates.[98] And, as these factors pertain to distributed solar generation, Mr. Rabago recommended a "value of solar" (VOS) analysis be conducted to quantify the avoided costs for rates paid to solar qualifying facilities, in addition to the marginal price of purchasing energy.[99] He further maintained that, in conducting the VOS analysis, Staff should use the values and methods set forth in the "PV Valuation Methodology: Recommendations for Regulated Utilities in Michigan," authored by Clean Power Research (CPR) for the Midwest Renewable Energy Association.[100] And, pursuant to that report, economic analysis of the following avoided costs is appropriate: avoided energy costs; avoided cost of resource adequacy; avoided cost created by advanced "smart" inverters: avoided transmission capacity cost; avoided distribution capacity costs; avoided environmental costs; and fuel price hedge value.[101]

Mr. Schumaker also testified on behalf of ELPC.[102] Specifically, Mr. Schumaker described the role of purchased power agreements (PPAs) in obtaining financing for development of a solar project – namely that the PPAs provide developers with the cash flows needed to make debt payments, cover operating expenses, and provide a

[98] 2 TR 149-150.
[99] 2 TR 151.
[100] 2 TR 151.
[101] 2 TR 151-152.
[102] Mr. Schumaker is the Director of Business Development for Sustainable Power Group LLC. His testimony is contained at 2 TR 160 through 2 TR 170 and he sponsored Exhibits ELP-6 and ELP-7.

reasonable return for investors.[103] He further testified the shortest PPA term required to make a solar project financeable is 15 years, but that such a term is not ideal as it requires a higher PPA rate than would be required under a 20-year PPA term, thus burdening ratepayers with additional cost.[104] According to an analysis that Mr. Schumaker prepared to demonstrate the impact of PPA terms and resulting shorter amortization periods on project financing, financing a PPA with a term of 10 or 15 years will require a developer to contribute more equity than compared to a PPA of 20 years, leading to lower equity returns and less ability for the project to obtain necessary funding.[105] Because of this, a shorter PPA term "significantly prejudices QF projects when competing at avoided cost rates which are based on conventional generators that are amortized over 20 years or longer."[106] In contrast, longer term PPAs and standard off contracts for up to 20 MW promote alternative energy projects by making it easier to obtain financing.[107] Mr. Schumaker further explained that the availability of longer contract terms and a standard offer for projects up to 20 MW are important elements in the states' implementation of PURPA because they promote alternative energy resources, diversify the electric power industry, and serve the public interest.[108]

Mr. Dueweke provided testimony regarding the critical role that the PPA serves in developing combined heat and power projects (CHPs).[109] Specifically, he testified:

> The PPA is the most critical contract in the effort to secure CHP project financing (equity and debt). This off-take agreement typically provides the

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[103] 2 TR 163.
[104] 2 TR 163-164.
[105] 2 TR 166; Exhibit ELP-6.
[106] 2 TR 168.
[107] 2 TR 169.
[108] 2 TR 169.
[109] Mr. Dueweke is a Senior Research Analyst with Sustainable Partners LLC, an alternative and renewable energy project development and consulting firm. His testimony appears at 2 TR 172 through 2 TR 175.

> project's owner with and sufficient revenue to pay its project debt obligation, covers the project's operating expenses, and provides a reasonable risk-adjusted return to investor(s). Lenders will look to whether or not there is a guaranteed revenue stream from a creditworthy purchaser that is sufficient to support the project's economics. The terms of the PPA determine whether equity investors and debt lenders view the project as financeable, and lenders are very concerned with the length of the PPA.[110]

Based on his experience developing CHP projects, Mr. Dueweke would not consider a CHP project economically viable nor attempt to procure third-party financing unless the PPA has a minimum 10-year duration.[111]

D. Rebuttal

Mr. Wallin and Mr. Jester provided rebuttal testimony on behalf of UPPCO and ELPC, respectively.

1. UPPCO

In his rebuttal testimony, Mr. Wallin responded to the direct cases filed by Staff and the ELPC. Mr. Wallin disagreed with Staff's rationale that Staff's proposed proxy methodology for calculating avoided costs should be applied to UPPCO because doing so is consistent with the methods used in the cases filed by Consumers Energy Company and DTE Electric Company. Mr. Wallin testified:

> Staff has not demonstrated why it is practicable to apply a method/practice which may be appropriate for the two largest electric utilities in the state of Michigan to one of the smallest in the state. Mr. Harlow fails to describe how the Company is similar enough to DTE and Consumers where consistent treatment is warranted. Other than participating in the Midwest Independent System Operator ("MISO") market, UPPCO is not similar to Consumers and DTE and this should be sufficient to support a Commission determination of avoided cost based on UPPCO's unique circumstances. Specifically, Consumers and DTE are large integrated utilities serving 1.8

[110] 2 TR 174.
[111] 2 TR 175.

> million customers and 2.2 million customers, respectively. UPPCO's customers total 56,000. Furthermore, Consumers and DTE have annual peak loads of over 8,700 MWs and 11,000 MWs, respectively, whereas UPPCO's annual peak load is only around 145 MWs. Finally, UPPCO's annual electric sales total less than 600,000 MWhs compared to almost 36 million MWhs for Consumers and 50 million MWhs for DTE.[112]

Given UPPCO's different circumstances and needs (UPPCO is projecting to need less than 25 MWs of additional capacity for the 2017/18 through 2019/20 MISO planning years), Mr. Wallin testified that UPPCO would neither be able to nor need to incur the costs to build a 210 MW combined cycle unit that serves the basis for Staff's avoided cost of capacity.[113] Despite these differences, Mr. Wallin maintained that Staff's analysis failed to consider methods other than the proxy plant methodology without explanation of whether such a method was proper for valuing capacity as it relates to UPPCO's avoided costs.[114]

Mr. Wallin also took issue with Staff's assertion that the annual capacity auction does not function as a "true" market. Specifically, Mr. Wallin noted that the MISO capacity auction prices reflect the cost to the utility to procure capacity in the event capacity is needed and, given that UPPCO will be purchasing capacity as needed rather than building generation, the auction prices constitute "one data point that should be considered when determining the incremental cost of capacity to the Company."[115]

Moreover, Mr. Wallin submitted, the actual prices that UPPCO paid for capacity for the next three years ($25,200/MW-year for 2017/8, $30,000/MW-year for 2018/19, and $36,000/MW-year for 2019/20) could be used to determine the cost to UPPCO of

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[112] 2 TR 40-41.
[113] 2 TR 42.
[114] 2 TR 43.
[115] 2 TR 44.

incremental capacity and are "evidence that the true incremental cost of capacity to the Company is nowhere near the $128,783.57/MW-year proposed by Staff."[116] Indeed, after this timeframe, assuming UPPCO were able to purchase capacity at prices greater than 20% of the negotiated contract prices, UPPCO would pay more for capacity from a QF than it would through the market under Staff's proposal – an outcome, Mr. Wallin argued, that is contrary to PURPA's requirement that "[n]o such rule prescribed under subsection (a) shall provide for a rate which exceeds the incremental costs to the electric utility of alternative electric energy."[117]

Mr. Wallin also disagreed with Staff's proposal regarding the avoided cost of energy, noting that UPPCO's size, circumstances, and options for obtaining energy and capacity are "unique unto itself."[118] Consequently, having to construct generating assets, instead of purchasing additional energy from MISO at the prevailing Locational Marginal Pricing (LMP), is not the most effective method for UPPCO to meet its customers' energy and capacity needs.[119] And, Mr. Wallin further rebutted, because the actual cost avoided by UPPCO is the lower of the cost of production associated with the avoided cost capacity resource, or the MISO real-time LMP, Staff's proposal to allow a QF to choose from a range of pricing options does not satisfy the definition of avoided cost.[120]

Mr. Wallin also testified that Staff's inclusion of the Fixed Investment Cost Attributable to Energy (ICE) to its energy price proposals was an unrealistic addition because, as Mr. Harlow acknowledged, "85% of the utilities in the MISO footprint are rate

[116] 2 TR 44.
[117] 2 TR 45.
[118] 2 TR 46.
[119] 2 TR 47.
[120] 2 TR 48.

regulated and are able to recover plant cost through traditional ratemaking."[121] Thus, "it is illogical to assume that utilities would also build an ICE component into the offer price for their generating assets."[122]

Although Mr. Wallin agreed with Staff's recommendation that the Commission review UPPCO's avoided cost and standard offer tariff on a biennial basis, Mr. Wallin testified that Staff provided no rationale for its recommendation that the Commission consider the utility's capacity needs during each biennial cost update filing and whether to increase the tariff size cap in the range of 1 to 5 MW – which is beyond what is legally required and could result in significant costs to the Company to accommodate the QF.[123] Were avoided costs set at those proposed by the Company, however, UPPCO could agree to increase the cap without a resulting negative impact on its customers.[124] Likewise, UPPCO is indifferent to the length of the contract term for QFs taking service under the standard offer tariff, so long as the Company's avoided costs are appropriately set.[125]

Mr. Wallin further noted that UPPCO agrees with the following recommendations made by Staff: (i) the Company will receive all the RECs associated with energy produced by QFs under the standard offer tariff; (ii) the Company will request *ex parte* processing when filing contracts for Commission approval based on the standard offer tariff; (iii) the ELCC is multiplied by the yearly capacity value to account for actual availability and is especially critical for determining capacity value of intermittent resources such as solar

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[121] 2 TR 49, referencing 2 TR 201, lines 3-5.
[122] 2 TR 49.
[123] 2 TR 49.
[124] 2 TR 50.
[125] 2 TR 51.

and wind; and (iv) the MISO ELCC ratios are to be applied to intermittent generator resources such as solar and wind.[126]

Responding to ELPC's direct case, Mr. Wallin disagreed with Mr. Rabago's assertion that avoided costs should be set based on factors other than procuring capacity and energy.[127] Nor should the Commission adopt Mr. Rabago's recommendation to consider avoided transmission costs, line loss mitigation, hedging value, avoided emissions, and environmental compliance costs as avoided costs because, according to Mr. Wallin, "each QF will come with a unique set of benefits and detriments that are difficult to quantify for purposes of setting a standard offer rate."[128]

Mr. Wallin further rejected Mr. Rabago's suggestion that the standard offer rate should be available to projects of 5 MW in size and up to 20 MW in size, maintaining that the QF size cap should be set according to PURPA requirements.[129] Mr. Wallin also rejected Mr. Rabago's assertion that UPPCO's avoided cost proposal would discriminate against QFs by not accounting for the full avoided cost because the true cost avoided by UPPCO is the cost to purchase energy and/or capacity, and not only the cost to a utility to construct its own generation.[130] Nor is Mr. Rabago correct, Mr. Wallin testified, that the Company is proposing to discriminatorily apply the rules applicable to large QFs to smaller QFs (20 MW and smaller) where UPPCO is proposing to make no payments for capacity to a QF during those years in which UPPCO does not need capacity.[131]

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[126] 2 TR 51.
[127] 2 TR 52.
[128] 2 TR 52.
[129] 2 TR 53.
[130] 2 TR 54.
[131] 2 TR 56.

Mr. Wallin further rejected Mr. Rabago's suggestion that a Value of Solar analysis would inform the PURPA avoided cost methodology issues because an equitable rate is determined by setting the rate equal to the avoided cost, which in turn is defined as the incremental costs to an electrical utility of electric energy or capacity or both.[132]

Mr. Wallin also characterized as "conjecture" Mr. Jester's recommendation that avoided cost rates should include all costs avoided by UPPCO when it purchases electricity from a QF (versus an alternative source or via utility self-regulation) inasmuch as any additional costs that may be avoided beyond the cost of energy and capacity would not be quantified and likely be unique to the QF and, thus, not automatically included in an avoided cost determination in a standard offer.[133] Similarly, Mr. Wallin disagreed with Mr. Jester's recommendation that the Commission should use the avoided costs per unit of useful capacity in the proxy plant, instead of per unit of nameplate capacity, because Mr. Jester's underlying assumption of annual load growth coupled with the Company's construction of 210 MWs of generation, is not relevant to UPPCO's circumstances.[134] Moreover, Mr. Wallin testified that Mr. Jester's assignment of a "useful value" definition to a generation asset overlooks the fact that any excess capacity built to meet forecasted demand in future years would still have "useful value" to the system as a whole.[135]

Also, requiring UPPCO to add language to future contracts requiring UPPCO to reduce its purchase obligations should its capacity and energy needs be reduced and

[132] 2 TR 56.
[133] 2 TR 58.
[134] 2 TR 58.
[135] 2 TR 59.

supplied by a QF, as suggested by Mr. Jester, would be “abnormal” according to Mr. Wallin because doing so:

> would likely reduce the number or[sic] counterparties willing to transact with the Company or the prices at which the Company is able to transact would rise as the counterparty would be subject to increased risk due to the opportunity cost associated with the risk of a decrease in the contracted sales volumes.[136]

Mr. Wallin further disagreed with Mr. Jester’s characterization of “clear evidence that MISO’s market prices are so distorted that they do not even approximately cover Michigan generator’s embedded costs of production.”[137] Mr. Wallin testified that Mr. Jester’s assertion, offered in support of a NGCC proxy plant, was unsupported by any evidence and overlooked the fact that market prices could be set based on the variable cost of a cola unit, combined cycle, combustion turbine, or even a hydro or wind unit provided there was enough capacity to meet the load requirement.[138]

2. ELPC

In his rebuttal testimony, Mr. Jester responded to the analysis and recommendations filed by Staff witnesses, Ms. Baldwin and Mr. Harlow.

Mr. Jester disagreed with Ms. Baldwin’s recommendation to calibrate the standard offer size cap based on the utility’s capacity needs forecast because, he maintained, the increased economic friction caused by increased transaction costs would limit the development of excess capacity.[139] Mr. Jester also disagreed with Mr. Harlow’s recommendation that the standard offer tariff capacity rate be set to the PRA auction price

[136] 2 TR 60.
[137] 2 TR 62, citing 2 TR 92-93.
[138] 2 TR 62.
[139] 2 TR 115.

if the utility's capacity forecast does not require capacity during the ten-year forecast period.[140] He explained that setting the rate at the PRA auction price would overlook circumstances such as anticipated capacity acquisitions through company-owned resources or power purchase agreements, as well existing capacity resources that could but may not be retired during the forecast period.[141] Mr. Jester further testified that Staff's recommended calibration of the standard offer contract terms to utility capacity position forecasts would create uncertainty and risk for developers because the proposed two-year recurrence of avoided cost proceedings lacks sufficient transparency of the process and "is barely sufficient for expeditious development of most qualifying facilities and insufficient for some types of projects."[142] Should there be a change in the capacity position on which avoided costs are based, Mr. Jester instead recommended a process whereby the utility could file an application to the Commission to make appropriate changes in its PRUPA avoided costs rates.[143]

Mr. Jester also did not support Ms. Baldwin's recommendation that standard offer contracts include the uncompensated transfer of renewable energy credits (RECs) produced by the qualifying facility to the utility. Specifically, Mr. Jester maintained that requiring a qualifying facility to negotiate with the utility would result in higher transaction costs to all parties or a decision not to develop the qualifying facility – either of which would be "potentially costly to society or the utility's customers."[144] Consequently, it cannot be said that transferring the value of the RECs from qualifying facilities to the utility

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[140] 2 TR 116.
[141] *Id.*
[142] 2 TR 116-117.
[143] 2 TR 118.
[144] 2 TR 118.

without compensation would be offset by the value of the standard offer contract.[145] Mr. Jester therefore recommended as an alternative that the Commission require the standard offer contract to include an option for the qualifying facility to decide whether to retain the RECs or transfer them to the utility pursuant to the contract, and that the Commission establish an avoided cost for the RECs included in the option.[146]

IV.

DISCUSSION

Based upon the record evidence and the parties' positions as summarized above, there is no disagreement amongst the parties with respect to the following four recommendations by Staff, which this PFD consequently recommends be adopted by the Commission: (i) the Commission should review UPPCO's avoided cost calculation and Standard Offer tariff on a biennial basis; (ii) UPPCO should request *ex parte* processing when filing contracts based upon the Standard Offer tariff for Commission approval; (iii) UPPCO's proposed Standard Offer tariff should be revised to replace the "PSCW" with the Michigan Public Service Commission; and (iv) UPPCO's proposed Standard Offer tariff should include the line loss information necessary to calculate the line loss savings for projects connected to transmission, primary and secondary levels.[147]

Conversely, the following five areas of dispute amongst the parties require resolution: (i) the appropriate methodology to be adopted for determining UPPCO's avoided capacity costs in UPPCO's service territory in potential PURPA contracts; (ii) the

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[145] 2 TR 119.
[146] 2 TR 120.
[147] 2 TR 49-51; 2 TR 182, 188-189.

appropriate methodology to be adopted for determining UPPCO's avoided energy costs in UPPCO's service territory in potential PURPA contracts; (iii) the necessary standard offer tariff language to address the design capacity and the appropriate length or term of the standard offer contracts; (iv) the appropriate treatment of other avoided expenses that could arise from the use of qualifying facility-generated power; (v) and the necessity of Staff's completion of a value-of-solar analysis. Each of these issues is addressed separately below.

A. <u>UPPCO's Avoided Capacity Costs</u>

The first issue to be resolved is the appropriate methodology that UPPCO should adopt for determining its avoided capacity costs under PURPA.

UPPCO maintains that, because of its size, UPPCO was unlikely to build assets to self-generate and would instead acquire supply from another source, rendering it more reasonable and appropriate to establish the utility's avoided cost on the cost to purchase capacity.[148] UPPCO further maintains that because it does not need to purchase capacity from a QF during the 2017/18 through 2019/20 MISO Planning Years, any requirement that it do so would impose unnecessary costs for excess capacity on UPPCO's customers. Therefore, during this time period, UPPCO submits that it should only be directed to purchase energy from a QF at the utility's incremental cost of energy, the Locational Marginal Price (LMP) in the MISO wholesale market.[149] And, with respect to the MISO Planning Year of 2020/21 and beyond, UPPCO submits that it should only be required to make a capacity payment to the QF based on the market cost to purchase

[148] UPPCO's Initial Brief, p. 10, citing 2 TR 29-30.
[149] *Id.*, citing 2 TR 37-38, 48.

capacity, a FERC-accepted methodology for determining avoided costs and one that would reflect the actual costs UPPCO would avoid but for the purchase of capacity from the QF.[150]

UPPCO further argues that its proposed market-based methodology results in capacity costs that are significantly less than those resulting from Staff's proposed proxy hybrid method. Specifically, UPPCO's annual purchase capacity prices are $25,000/MW, $30,000/MW, and $36,000/MW for MISO Planning Years 2017/18, 2018/19 and 2019/20, respectively, whereas Staff's proxy hybrid method reflects a capacity value of $128,783.57/MW per year.[151] Thus, UPPCO maintains that its avoided cost method is the only proposal in the instant case that is consistent with PURPA, which requires the rates for purchases by electric utilities to "be just and reasonable to the electric customers of the electric utility and in the public interest."[152] In this regard, UPPCO submits that a uniform "one-shoe-fits-all" policy that requires UPPCO to adopt the same methodology used by dissimilar utilities, or the other methodologies identified by the Commission would ultimately thwart the utility's efforts to reduce power supply costs for its customers and would not result in "incremental", "but for" costs, or "reasonable" rates as required by PURPA.[153]

Staff, on the other hand, maintains that its proposed modified proxy unity method, as presented by Mr. Harlow, "combines a combustion turbine proxy unit for capacity and market based pricing for energy" and, furthermore, "a component is included that

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[150] *Id*., p. 11, citing 2 TR 46.
[151] *Id.*, citing 2 TR 31, 43-44.
[152] UPPCO's Initial Brief, p. 11.
[153] UPPCO's Initial Brief, p. 12, citing 2 TR 57.

represents the cheaper market energy cost that is attributed to a combined cycle natural gas plant when the capacity proxy used is a combustion turbine."[154] According to Mr. Harlow, the use of a natural gas combustion turbine (CT) value in Staff's proposed capacity model better aligns with the actual capacity value provided by a QF through a long-term contract, and also differs from the model presented in Staff's TAC Report as follows:

> Staff's capacity model attached as Exhibit S-3 (JJH-2) uses the inputs from the DTE Electric Company's filing in U-18091 for a NGCC and then applies a ratio comparing a NGCC and CT based on Consumers Energy Company's confidential avoided cost filing in Case No. U-18090. This was the most comprehensive data that Staff had available as the Company did not provide this data in its filing. Staff recommends that the Company adopt Staff's model and update it with inputs specific to and based on its filings with the Commission going forward.[155]

As such, Staff submits that its method provides the most accurate valuation of UPPCO's avoided capacity costs using both the market-based approach and the proxy plant method, without reliance on the MISO capacity auctions, which neither accurately value long term capacity nor send appropriate market signals.[156] Staff also supports the consistent application of methods and has proposed this same method in the avoided cost proceedings of Consumers Energy Company and DTE Electric Company, Case Nos. U-18091 and U-18091, respectively.[157]

Although generally supportive of Staff's proposed methodology as "a just and reasonable avoided cost methodology," ELPC recommends that the Commission determine UPPCO's avoided costs in two phases, the first of which would extend until the

[154] Staff's Initial Brief, p. 20, citing 2 TR 199.
[155] 2 TR 202; Exhibit S-3.
[156] 2 TR 199-200; Exhibit S-2.
[157] 2 TR 196-197.

end of UPPCO's current power supply contracts on May 31, 2020 and be based on the terms of those contracts as well as account for all potential avoided costs, and the second phase would begin on June 1, 2020 and be based on Staff's proxy plant method with five modifications, as outlined in Mr. Jester's testimony in summarized in Section III above.[158]

As noted above, the Commission has initiated proceedings in separate dockets for the purpose of determining the avoided cost methodologies and costs to be used by the electric providers pursuant to PURPA.[159] On May 31, 2017, the Commission issued its first order in this series of proceedings with respect to Consumers Energy Company.[160] Therein, Consumers had proposed an avoided cost methodology based entirely on a NGCC proxy plant, where the capacity component would be based on the levelized fixed cost of a NGCC plan and the energy component is either: (i) the lesser of the forecasted LMP or forecasted variable cost of a NGCC plant, or (ii) the lesser of the actual LMP or the actual variable cost of a NGCC plant, where actual or forecasted energy price compensation is per the choice of the QF.[161] However, the Commission concluded that Staff's proposed hybrid proxy method is "the most appropriate model for calculating avoided costs pursuant to PURPA."[162] The Commission explained its reasoning:

> As several parties point out, the purpose of PURPA, and the avoided cost calculation, is not to set prices that reflect the lowest-cost incremental capacity and energy, but to provide non-discriminatory treatment to QFs by setting prices that are just and reasonable, in the public interest, and that mirror what the utility would have paid if it purchased or built the resource itself. 18 CFR 292.101(b)(6). Thus, the Commission agrees with the Staff,

[158] 2 TR 82-85.
[159] MPSC Case No. U-18089, May 3, 2016 Order, p. 2.
[160] MPSC Case No. U-18090, May 31, 2017 Order.
[161] *Id.*, p. 7.
[162] *Id.*, p. 17.

> IPPC, ELPC, and GLREA that Consumers' proposals for calculating avoided capacity and energy costs rely inappropriately on short-term market prices.
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> As acknowledged by the ALJ, the Commission also finds that PURPA avoided cost is a more detailed inquiry than transfer price, which, as Consumers points out, is primarily used to allocate Act 295 renewable energy costs between power supply and incremental costs of compliance. The Commission agrees with the Staff that in the event that Consumers requires additional capacity only, the company would theoretically build an NGCT unit. As the Staff argued, this type of unit could be built quickly, at a relatively low cost, and a NGCT can be cycled on and off when additional capacity is required. On the other hand, if the company requires additional energy, an NGCC unit would be the most appropriate generating unit due to the low cost of the energy produced.[163]

In the instant case, because UPPCO currently has contractual arrangements supplying its capacity needs until May 31, 2020, a status acknowledged and not disputed by Staff, this PFD agrees with UPPCO and ELPC that, until those arrangements expire, UPPCO's avoided capacity costs should be based on the prices specified in those contracts.[164] However, this PFD further finds that UPPCO's proposal for calculating avoided capacity costs following the expiration of UPPCO's existing contractual arrangements in May 2020 based on the market cost to purchase capacity must be rejected because, as the Commission concluded regarding Consumers Energy's similar proposal, it "rel[ies] inappropriately on short-term market prices."[165] Although Mr. Wallin maintained that such an approach based on the market is more reflective of the Company's current avoided costs because "the MISO capacity auction prices reflect [sic] the cost to the utility to procure capacity in the event capacity is needed,"[166] he also did

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[163] *Id*. (Emphasis added).
[164] Staff's Initial Brief, p. 19; 2 TR 30, 78-79.
[165] MPSC Case No. U-18090, May 31, 2017 Order, p. 17.
[166] 2 TR 43-44.

not substantively disagree with the following explanation provided by Mr. Harlow of why the MISO Planning Reserve Auction (PRA) does not accurately value long term capacity and does not send appropriate market signals:

> MISO's PRA treats capacity as annual, excess rate-regulated utility capacity since the PRA currently serves only as a market for differences. Using the PRA to value a QF's long-term capacity undervalues the capacity of the QF as the QF's capacity is long term, firm capacity. Utilities in the MISO footprint forecast capacity needs well into the future and build or enter into long-term contracts to meet these capacity requirements. The PRA was established for balancing functions to make up small zonal resource credit shortfalls in the upcoming or following year and is not intended to support resource investment decisions. It would be prudent for a regulated utility to plan to build a plant or enter into a long term contract should a large long term capacity need exist, not purchase this capacity shortfall from the PRA. The PRA prices tend to be especially low compared to the cost of adding new capacity given that over 85%3 of the utilities in the MISO footprint are rate-regulated and are able to recover generation plant costs through traditional rate making. The PRA was never intended for an unregulated market as a mechanism for generation plants to recover capacity costs. Due to these market characteristics, the PRA does not function as a "true" market as it will likely never produce price signals that prompt capacity build-outs and the utility itself would never utilize the PRA as the sole source of capacity cost recovery for long-lived generation plant investments absent traditional regulated cost recovery.[167]

More recently, the Commission demonstrated a similar understanding of the MISO capacity market:

> [T]he MISO capacity market was not designed as the primary mechanism to ensure resource adequacy. Rather, MISO's capacity market was intended to complement state resource adequacy authorities and actions, such as retail rate regulation of vertically-integrated utilities and integrated resource planning. *Id.* Accordingly, the MISO capacity market serves as a mechanism to sell and buy capacity in the near-term (i.e., current year) to allow for a more efficient exchange of planning resources across energy providers and local planning zones. MISO and other entities have explained that the MISO market, on its own, does not provide the necessary price signals to new or existing generators in order to meet long-term resource adequacy needs.[168]

[167] 2 TR 200-201. (Footnotes omitted).
[168] MPSC Case No. U-18197 et al, June 15, 2017 Order, pp. 3-4. (Footnote omitted).

Given the foregoing, it cannot be said that UPPCO's proposed market based pricing methodology is the most reasonable and accurate method for determining UPPCO's avoided capacity costs. Instead, based on the record evidence and against the backdrop of the Commission's recent PURPA-related decision, this PFD finds that Staff's proposed hybrid proxy methodology is most consistent with the intent of PURPA and the State of Michigan's application of that statute to utilities within the state. To be sure, Staff's proposal utilizes the levelized cost of a natural gas combustion turbine (NGCT) as the proxy plant for capacity because an NGCT aligns with the actual capacity value a QF provides through a long-term contract.[169] And, as observed by ELPC, NGCTs are the resource most commonly used to provide the reserve margin a utility needs to meet MISO capacity requirements.[170] As such, "an NGCT is the best measure of the incremental cost the Company actually avoids by entering into long-term QF contracts."[171]

Nonetheless, the record further supports the use of UPPCO's calculation of a smaller combustion turbine proxy plant with a design capacity of 85 MW, rather than Staff's use of a 330 MW combustion turbine, in Staff's capacity model.[172] Indeed, while Staff's capacity model "uses the inputs from the DTE Electric Company's filing in U-18091 for a NGCC and then applies a ratio comparing a NGCC and CT based on Consumers Energy Company's confidential avoided cost filing in Case No. U-18090,"[173] UPPCO's 85 MW estimate was obtained from the U.S. Energy Information Administration's April 2013 report titled Updated Capital Cost Estimates for Utility Scale Electricity Generating

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[169] 2 TR 201.
[170] 2 TR 91.
[171] ELPC's Initial Brief, p. 8.
[172] 2 TR 32, 202; Exhibit S-3.
[173] 2 TR 202, 212; Exhibit S-3.

Plants, which contains detailed specifications for a hypothetical, conventional CT with a nominal capacity of 85 MW, based upon the state where the facility is constructed.[174]

Moreover, this PFD finds Staff's adjustment based on the Effective Load Carrying Cost (ELCC) of the QF and the proxy plant is just and reasonable based on Mr. Harlow's testimony that "[t]he ELCC recognizes the historical availability and output of the intermittent generation types during on-peak periods" and, thus accounts for the avoided costs associated with intermittent resources such as solar and wind.[175]

Finally, although UPPCO has not proposed a capacity planning horizon beyond consideration of one year at a time, this PFD agrees with Staff's recommendation that UPPCO be required to pay for QF capacity "if the Company shows any capacity need over the PURPA ten-year capacity planning horizon, up to the point that the projected capacity need is met" and, "[o]nce the need is met with the incremental QF capacity, the Company should apply to the Commission to have the capacity rate adjusted so that QF facilities are compensated using a planning resource auction (PRA) for capacity."[176] However, as noted by ELPC, the planning horizon's 10-year timeline should not begin until June 1, 2020 in recognition of UPPCO's contractual arrangements for power through May 31, 2020.[177] This approach is not only consistent with PURPA regulations, which require that UPPCO file with the Commission and make publically available their capacity forecast for the next ten years, but it is also consistent with the Commission's recent determination in Case No. U-18090 that "a 10-year planning horizon is most appropriate

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[174] 2 TR 32.
[175] 2 TR 202.
[176] 2 TR 31,198.
[177] ELPC Initial Brief, p. 11, citing 2 TR 108.

for determining capacity requirements, that avoided costs established in this proceeding should only apply to new and renewed contracts, and that existing contracts should not be altered."[178]

Accordingly, this PFD recommends that the Commission adopt UPPCO and ELPC's recommendation that UPPCO's avoided capacity costs be based on the prices specified in UPPCO's existing contractual arrangements for its capacity needs through May 31, 2020. With respect to the calculation of UPPCO's avoided capacity costs following the May 31, 2020 expiration of UPPCO's existing contractual arrangements, this PFD recommends that the Commission adopt Staff's proposed hybrid proxy methodology, with Staff's proposed ten-year planning horizon timeline beginning on June 1, 2020 as recommended by ELPC, and incorporating UPPCO's calculation of a smaller combustion turbine proxy plant with a design capacity of 85 MW, rather than Staff's use of a 330 MW combustion turbine, as well as Staff's adjustment based on the ELCC of the QF and the proxy plant.

B. UPPCO's Avoided Energy Costs

Of the three options proposed by Staff for the QF for the energy component of the avoided cost methodology, UPPCO agrees with the first option – specifically, that UPPCO should only be directed to purchase energy from a QF at the time of delivery at the Locational Marginal Price (LMP) in the MISO wholesale market.[179] UPPCO maintains that neither of Staff's other two proposed options [(ii) basing the energy component on the utility's forecast of LMPs over the duration of the contract, providing compensation for

[178] 18 CFR § 292.302(b)(2); MPSC Case No. U-18090, May 31, 2017 Order, p. 18.
[179] 2 TR 37-38, 48.

energy on an hourly or monthly basis; or, (iii) basing the energy component to be paid by the utility on the forecasted variable cost of a natural gas combined cycle plant] is representative of UPPCO's true avoided cost because:

> UPPCO is a small utility and its circumstances and options for obtaining energy and capacity are unique unto itself. Constructing generating assets may not be the most effective method for UPPCO to fulfill its customers' energy and capacity needs and any determination of avoided cost using the hypothetical cost of constructing a plant is counter to the definition of avoided cost. As a MISO market participant, UPPCO has unrestricted access to a robust and efficient energy market. If UPPCO needs to procure additional energy to meet its customer demand, UPPCO is able to purchase that energy from MISO at the prevailing Locational Marginal Pricing ("LMP"). UPPCO also delivers energy into the MISO market and is paid the prevailing LMP for the energy it delivers. Allowing QFs to be paid based on a forecasted energy price does not accurately represent the actual cost of energy at the time it is received from the QF. The Commission does not ultimately allow UPPCO to recover its cost of purchased power based solely on estimates/forecasts; therefore, the first option that provides energy payments to the QF at the LMP at the time of delivery should be adopted.[180]

UPPCO disagrees, however, with Staff's proposed inclusion in each of Staff's three proposed options of a fixed investment cost attributable to energy (ICE), arguing that such a cost is an unnecessary component of the energy cost and not reflective of UPPCO's avoided cost.[181] Mr. Harlow explained the necessity of this component as follows:

> Staff's[sic] recommends that energy payments to the QF include a fixed investment cost attributable to energy in addition to the LMP, LMP forecast or the NGCC operating cost forecast. The rationale is that in order to realize a cheaper energy price on the market, additional capital costs to build an NGCC are incurred over and above the cost to build a CT, as a CT would generally be built to provide cheap capacity while an NGCC would be built to provide cheap energy.
> ***
> As mentioned above, an NGCC provides for lower energy cost, but results in higher capacity cost when compared to a CT. The NGCC fixed ICE is calculated using the fixed capacity cost difference between an NGCC and a CT as shown in Exhibit S-3 (JJH-2), Page 2 of 2. Staff calculated this

[180] UPPCO's Reply Brief, p. 7, citing 2 TR 46-47.
[181] UPPO's Reply Brief, pp. 7-8; 2 TR 205.

> value by subtracting the fixed costs to construct a CT from the fixed costs to construct an NGCC. This difference in cost is paid on a volumetric basis and is added to the energy payment to represent a market energy value. Similar to the capacity component in Staff's calculation, Staff utilized the Company's inputs to update the fixed ICE calculation.[182]

Relying on the testimony of Mr. Jester and Mr. Rabago, as summarized above, ELCC maintains that Staff's proposal of three alternative measures of the Company's avoided cost of energy "complies with PURPA as long as the QF retains the right to choose which method it prefers."[183] However, ELCC further submits that the Commission should adopt Staff's third option and set the cost of avoided energy at the forecasted variable cost of an NGCC plant, along with the application of the ICE adder, as recommended by Staff.[184]

Here again, this PFD finds that Staff's proposed pricing structure for avoided energy costs – specifically, giving the QFs the choice of: (i) adopting energy prices based on the actual LMP, (ii) using the then-existing forecasted LMP price over the term of the contract, or (iii) accepting a proxy price based on the forecasted variable energy cost of a NGCC plant, along with an ICE adder applied to each method – presents the most reasonable approach because, as articulated by Mr. Harlow, it ensures protecting the interests of UPPCO, its customers, and the QFs from under- or overinflated energy prices. Moreover, the Commission has endorsed this same approach with Consumers Energy Company, including the application of the ICE adder, concluding as follows regarding the latter:

> The Commission also agrees that the ICE payment added to energy cost is appropriate. As ELPC points out:

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[182] 2 TR 205-206.
[183] ELPC's Initial Brief, p. 11, citing 2 TR 129-130 and 2 TR 87-88.
[184] *Id.*, p. 13.

> The ICE adjustment is necessary to reflect the fact that if the energy cost Consumers avoids is the variable cost of an NGCC plant, Consumers has necessarily made the investment to build an NGCC plant. Incorporating the investment cost attributable to that energy does not, as Consumers contents, conflate capacity costs with energy costs. The ICE does not "double count" capacity because it is a measurement of the **difference in cost** between building a NGCT and a NGCC. … A NGCC is more expensive to build than a NGCT, and the ICE represents the difference (**and only the difference**) in cost between building the two units. The ICE is not, as Consumers argues, a cost of capacity – it is a component of Consumers' cost of energy from a NGCC.[185]

Accordingly, this PFD recommends the Commission adopt Staff's proposed three-option methodology for the calculation of UPPCO's avoided energy costs, incorporating the ICE adder to each method.

C. Standard Offer Tariff

1. Design Capacity

The Standard Offer is a tariffed rate paid to QFs through a standard contract with the utility. PURPA regulations require electric utilities to establish standard rates for purchases from QFs with capacity of 100 kW or less, but the regulations also give state commissions the authority to apply the Standard Offer to larger projects.[186]

As noted earlier, UPPCO has proposed the continuation of a standard tariff limit for QFs based on a design capacity of 100kW or less, as required by PURPA, with QFs larger than 100kW having to negotiate with UPPCO to obtain a contract.[187]

In contrast, Staff recommends a 1 MW standard offer QF size cap for UPPCO and

[185] MPSC Case No. U-18090, p. 18, citing ELPC's replies to exceptions, pp. 4-5, citing 2 TR 43; 163-164 (emphasis in original).
[186] 18 CFR 292.304(c)(1) and (2). See also, MPSC Case No. U-18090, May 31, 2017 Order, p. 20.
[187] 2 TR 49-50; Exhibit A-1.

that the Commission consider the capacity needs of the utility during each annual avoided cost update filing to set the standard offer size cap.[188] As Ms. Baldwin explained:

> Factors the Commission may want to consider are how much capacity the utility needs in the next year and how much the utility needs during the entire 10-year PURPA capacity planning horizon. Capacity from the renewal of existing PURPA contracts should be appropriately figured into the Company's capacity position also. If a utility needs a significant amount of capacity during the succeeding year, then Staff recommends the QF Standard Offer size cap be set at the higher end of the range and closer or equal to 5 MW. If the capacity need is further out in the PURPA 10-year capacity planning horizon, then a smaller Standard Offer size cap set at 1 MW may cause QF capacity to build more slowly. For a utility like UPPCO with no capacity needs until at least until 2021, Staff recommends a 1 MW Standard Offer QF size cap. The Company's capacity needs for the latter part of the 10-year PURPA planning horizon are unknown.[189]

ELPC, on the other hand, recommends the Commission make the standard offer available to QFs with a design capacity of at least 5 MW.[190] Doing so, ELPC submits, particularly for projects that face discriminatory access to wholesale markets would promote growth of QFs by reducing transaction costs and, thus, "strikes a balance between promoting the goals of PURPA and taking into consideration UPPCO's smaller size compared to other utilities in Michigan."[191]

UPPCO disagrees with the recommendations of Staff and ELPC because, as explained by Mr. Wallin:

> PURPA only requires that the standard offer tariff apply to facilities of 100kW or less in size. Staff has offered no rationale as to why is [sic] would be appropriate to increase the size cap beyond what is legally required. Furthermore, an increase in the size cap could push costs for

[188] 2 TR 184; Exhibit S-1. (It should be noted that, while Exhibit S-1 contains Staff's revised version of UPPCO's Standard Offer Tariff contained in Exhibit A-1, , Exhibit S-1 fails to indicate by strike-through lines that the language "total customer owned generating capacity of 1 MW or less," replaces UPPCO's language "total customer owned generating capacity of 100 KW or less.")
[189] 2 TR 184-185.
[190] ELPC's Initial Brief, p. 18, citing 2 TR 109.
[191] *Id.*, citing 2 TR 109-110.

> interconnecting these larger facilities to the customers unless the QF is required to be responsible for any associated costs the Company incurs in order to upgrade the Company's equipment or distribution system to accommodate the QF. Smaller QF under the 100kW size cap would likely not result in a significant upgrade in equipment or facilities, however, even a 1 MW QF interconnecting at certain points on the Company's distribution system could result in significant costs that should ultimately be borne by the QF.[192]

Based on the evidence provided in this case, the intent of PURPA, and recent Commission precedent, this PFD finds that Staff's recommendation should be adopted, with a 1 MW QF cap to begin immediately, given that UPPCO has no capacity needs until 2021, and with a reset anywhere from 1 to 5 MW, depending on the Commission's consideration of UPPCO's capacity needs in its planning horizon during each annual avoided cost update filing. Although UPPCO has expressed concern that an increase in the size cap could lead to increased costs associated with its equipment or distribution system upgrades, costs ultimately borne by its customers, this concern is merely speculative at this stage, without evidentiary support. Whereas, as Ms. Baldwin observed, Michigan has experienced very little growth in QF development in the last twenty years and it remains to be seen how much PURPA development will occur in Michigan in the new few years.[193] Moreover, ELPC's arguments in support of making the standard offer available to QFs with a design capacity of at least 5 MW in order to reduce transaction costs were previously considered and rejected by the Commission.[194]

Consequently, this PFD recommends the Commission adopt Staff's recommendation that the Standard Offer be limited to QFs of 1 to 5 MW, with a 1 MW cap

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[192] 2 TR 49-50; 2 TR 53.
[193] 2 TR 185.
[194] MPSC Case No. U-18090, May 31, 2017 Order, p. 23.

initially, to be revisited in the Company's next avoided cost filing.

2. <u>Length of Contract (Term)</u>

While UPPCO has indicated it is "indifferent" to the length of the Standard Offer contract term so long as avoided costs are appropriately set for the Company, Staff recommends that QFs taking service under the Standard Offer tariff have the option to select 5, 10 or 15 years as the contract term.[195] Noting that the Company's proposed Standard Offer tariff does not specify a contract length, Ms. Baldwin testified that the length of the contract can provide certainty and can be a factor that results in a feasible QF project.[196] She further explained that existing PURPA contracts have long terms and Act 295 PPAs for projects with design capacities of 20 MW or less, approved for Consumers Energy and DTE, show that contract terms are primarily in the 20 year range.[197] She also described the impact on utility customers if a QF is given the option to select a 5, 10 or 15-year Standard Offer contract term:

> One benefit to customers is the long-term commitment of capacity to the utility. If a forecasted energy rate is selected by the QF, see 18 CFR 292.304(d)(2)(ii),the difference between the actual and the forecast could be either positive or negative for utility customers. Under a 5, 10 or 15 year contract, the QF would receive certainty of capacity and energy payments (as long as the "As Available" energy option was not selected).[198]

ELPC recommends that the Commission adopt a contract term of no less than 15 but, preferably, 20 years, arguing that an adequate term length prevents discrimination against QFs and furthers the goals of PURPA.[199] More specifically, Mr. Schumaker

[195] 2 TR 51; 2 TR 185.
[196] 2 TR 186.
[197] *Id.*
[198] 2 TR 186-187.
[199] ELPC's Initial Brief, p. 19.

testified that a standard offer term that is too short "prejudices QF projects when competing at avoided cost rates which are based on" non-QF projects "that are amortized over 20 years or longer."[200] He further observed that, because debt providers will typically finance QF projects for the length of a PPA or less, a longer standard offer term length allows more debt to be secured by the contract which, in turn, leads to a QF project that is financed without the hindrance of a too-short standard offer term.[201]

This PFD finds that the Commission should adopt ELPC's recommendation of a contract term of at least 15 years. Not only will this 15-year term provide greater certainty and debt securitization to QFs, as set forth in the evidentiary presentations of Staff and ELPC, but it is fairly close to the 17.5 year term contained in Michigan law, such as Act 304 and MCL 460.6j, and remains consistent with the Commission's first decision thus far issued in these underlying PURPA proceedings, wherein the Commission rejected Staff's same recommendation (of a 5, 10, or 15 year option) and instead adopted ELPC's proposal of a minimum of 15 years to attract investment and financing.[202] Furthermore, as noted earlier, although Mr. Wallin testified that UPPCO is "indifferent" to the contract term so long as avoided costs are appropriately set for the Company, UPPCO has otherwise failed to present a substantive challenge to the recommendations of Staff and ELPC.[203]

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[200] 2 TR 168.
[201] 2 TR 164-166.
[202] MPSC Case No. U-18090, May 31, 2017 Order, pp. 21-23.
[203] UPPCO incorrectly represents Mr. Wallin's testimony to say that "unless its avoided cost methodology is adopted, the term of the contract as proposed by Staff is not appropriate." UPPCO's Reply Brief, p. 10, citing 2 TR 50-51.

Accordingly, this PFD recommends that the Commission adopt ELPC's recommendation of a minimum 15-year Standard Offer contract term option for QFs.

D. **Other Avoided Expenses**

1. **Renewable Energy Credits**

Both UPPCO and Staff are in agreement that, under the Standard Offer, renewable energy credits (RECs) should be transferred to the Company without any compensation to REC-generating QFs.[204] Ms. Baldwin explained the basis for Staff's recommendation:

> The availability of a Standard Offer tariff is a benefit to QFs because they do not have to negotiate with the utility. In exchange for this simpler contracting experience, the utility customers should have the benefit of the RECs.[205]

ELPC disagrees with this approach, however, and instead argues that the Commission should reject Staff and UPPCO's proposal because "FERC has made clear that RECs are separate from the energy and capacity purchases, and UPPCO should not be allowed to benefit from the REC value generated by the QF without compensating the QF for that value."[206]

The Commission recently agreed with ELPC's interpretation of *Windham Solar* concerning the ownership of RECs, concluding as follows:

> [T]he amounts paid for energy and capacity do not include compensation for RECs. Accordingly, the QFs may sell the RECs to the host utility or otherwise disposed [sic] of them at the QF's option.[207]

There being no evidentiary basis presented in this record to depart from the

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[204] Staff's Initial Brief, p. 12, citing 2 TR 188; UPPCO's Initial Brief, p. 12, citing 2 TR 51.
[205] 2 TR 188.
[206] ELPC's Reply Brief, p. 4, citing *Windham Solar LLC and Allco Finance Ltd*, 156 F.E.R.C. P61.042, ¶ 4 (2016) (explaining that RECs are wholly separate from avoided cost rates for energy and capacity).
[207] MPSC Case No. U-18090, May 31, 2017 Order, p. 26.

Commission's determination on this issue, this PFD recommends that the Commission reject UPPCO and Staff's proposal and instead adopt ELPC's recommendation to recognize that QFs may either sell the RECs to the Company or dispose of them at the QF's option.

2. **Transmission Costs, Line Loss Mitigation, Hedging Value, Avoided Emissions, Environmental Compliance Costs**

ELPC maintains that other avoided costs, such as reduced transmission costs, line loss mitigation, hedging value, avoided emissions, and environmental compliance costs, should be included in the computation of the rates applied to QFs and recommends that the Commission establish a separate procedure for calculating these costs. [208] Mr. Rabago explained ELPC's recommendation:

> ELPC provided detailed comments which generally support the Staffs' Strawman Proposal and offer additional recommendations for improvement. In particular, I support ELPC's recommendations that the Commission's approved methodology must leave room for technology-specific determinations in regard to ELCC and should require consideration and quantification of costs related to the factors listed in federal regulations that support calculation of the utilities full avoided costs, taking into account technology-specific values. The Commission should require consideration of the following specific types of avoided costs:
> - Avoided transmission costs.
> - Line loss mitigation.
> - Hedging value.
> - Avoided emissions and environmental compliance costs.
> - Avoided costs revealed through a comprehensive Value of Solar analysis.[209]

UPPCO did not address the treatment of other avoided costs in its proposal or its pleadings, however Mr. Wallin testified that he disagreed with Mr. Rabago's

[208] ELPC's Reply Brief, p. 3, citing 2 TR 135-136.
[209] 2 TR 135 (footnotes omitted); see also, Exhibit ELP-4.

recommendation that such costs should be considered as avoided costs for these reasons:

> First, each QF will come with a unique set of benefits and detriments that are difficult to quantify for purposes of setting a standard offer rate as is the purview of this proceeding. Second, Mr. Rabago's position is illogical from a financial perspective. For example, assuming the addition of a QF would result in a reduction to the Company's line losses and associated costs and this reduction is then paid to the QF, the customer sees absolutely no cost benefit of adding the QF and would therefore be indifferent.
>
> However, if the Company would construct a generator that also resulted in line losses and associated costs, these cost savings would be passed directly to the ratepayer. Under this scenario, the customer would likely prefer the solution that resulted in lower costs. Furthermore, Mr. Rabago bases his premise on the factors he lists at pages 20-21 of his prefiled direct testimony; however, these factors make no mention of full avoided cost and only specifically call out cost savings from line losses. Additionally, when considering this list it is important to note that in regard to line losses Mr. Rabago has not included language relative to the situation I describe above. The exact language from Mr. Rabago's reference is provided below with the highlighted section reflective of the missing portion:
>
> > "The costs or savings resulting from variations in line losses from those that would have existed in the absence of purchases from a qualifying facility, **if the purchasing electric utility generated an equivalent amount of energy itself or purchased an equivalent amount of electric energy or capacity**."[210]

Likewise, neither Staff's witnesses nor Staff's Initial Brief included a specific recommendation regarding the treatment of these other avoided costs, but Staff did address the issue in Staff's PURPA report, contained in Staff's Exhibit S-2, wherein Staff recommended the following:

> Distributed generation has the potential to reduce transmission costs, and can help to mitigate line losses. This benefit is location specific because it depends on the unique supply and load characteristics of the local area. <u>Staff recommends that transmission costs and line loss mitigation with</u>

[210] 2 TR 52-53. (Emphasis in original).

respect to the avoided cost calculation be evaluated on a case by case basis for inclusion in the avoided cost rate, at the request of the QF.[211]

Based on the record in this case, this PFD finds there is insufficient information available to quantify these costs, much less determine the appropriateness of their inclusion in the avoided cost rate. Consequently, this PFD recommends that the Commission adopt Staff's recommendation set forth in its PURPA Report – specifically, that the miscellaneous avoided costs or benefits provided by reduced transmission costs, line loss mitigation, hedging value, avoided emissions, and environmental compliance costs should be evaluated on a case-by-case basis for inclusion in the avoided cost rate, at the request of the QF. This approach is also not unlike that adopted by the Commission in Case No. U-18090, wherein the Commission did not explicitly determine whether avoided transmission costs, hedging costs, reduced emissions and environmental compliance costs should be included in the avoided cost calculation, but instead concluded that there is "insufficient information in the record to quantify other avoided costs, except for line-loss credit, and that parties may include analyses of these costs in the next PURPA review proceeding."[212]

E. Value-of-Solar Analysis

ELPC further recommends that the Commission direct Staff to "build on the work already done" through the Commission's Solar Working Group and develop a full and complete solar valuation study and require UPPCO to participate in this process and

[211] Exhibit S-2, p. 30. (Emphasis added).
[212] MPSC Case No. U-18090, May 31, 2017 Order, p. 26.

provide all information necessary to complete the analysis.[213] Mr. Rabago explained the reasoning behind ELPC's recommendation:

> [A] properly crafted Value of Solar study would cast a wide net in evaluating the cost and benefits of distributed solar generation, leaving it to the Commission to decide which real avoided costs should be reflected in rates. Over time, as experience and quantification techniques improve, the biennial review process will provide for an opportunity to adjust rates. Consideration of all of these costs avoided by the utility will ensure that the avoided cost is not limited to the marginal price of purchasing energy, but rather includes all the incremental costs avoided as a result of the purchase from the qualifying facility.[214]

This recommendation also was not addressed by UPPCO and Staff in the parties' respective briefs, however Mr. Wallin testified that he disagreed with Mr. Rabago's suggestion that a Value of Solar analysis would help inform the PURPA avoided cost methodology:

> As stated on page 5 of Ms. Hadala's direct testimony, an equitable rate is established by setting the rate equal to the avoided cost, and avoided cost is defined as the incremental costs to an electric utility of electric energy or capacity or both.[215]

Notwithstanding the parties' respective positions, it must be noted that the Commission recently considered and declined to adopt ELPC's same recommendation in its order issued in Case No U-18090, concluding therein:

> ELPC's recommendation that a VOS analysis be undertaken is potentially duplicative, given the directive under the new energy legislation, which requires the Commission to create a distributed generation program and examine costs associated with distributed generation and net metering. MCL 460.1173 and MCL 460.6a(14). Accordingly, the Commission anticipates that VOS issues, as well as other avoided costs associated with

[213] ELPC Initial Brief, pp. 16-17, citing SOLAR WORKING GROUP, STAFF REPORT, Case No. U-17302 at Dkt. #106 (July 1, 2014), and 2 TR 144-145.
[214] 2 TR 152-153.
[215] 2 TR 56.

distributed generation generally, will be examined as part of these proceedings, which will be completed before the next PURPA review.[216]

Because the record in this case has afforded no basis to depart from the Commission's disposition of ELPC's identical recommendation in Case No. U-18090, this PFD similarly recommends that the Commission forego ELPC's recommendation that Staff be required to undertake a "potentially duplicative" VOS analysis in the instant proceeding.[217]

V.

CONCLUSION

Based on the foregoing discussion, this PFD recommends that the Commission adopt the findings, conclusions, and recommendations set forth above, specifically as follows:

1) Adopt UPPCO and ELPC's recommendation that UPPCO's avoided capacity costs be based on the prices specified in UPPCO's existing contractual arrangements for its capacity needs through May 31, 2020.

2) For the calculation of UPPCO's avoided capacity costs following the May 31, 2020 expiration of UPPCO's existing contractual arrangements: (i) adopt Staff's proposed hybrid proxy methodology; (ii) adopt Staff's proposed ten-year planning horizon timeline beginning on June 1, 2020; (iii) incorporate UPPCO's calculation of a smaller combustion turbine proxy plant with a design capacity of 85 MW, rather than Staff's use of a 330 MW combustion turbine; and (iv)

[216] MPSC Case No. U-18090, May 31, 2017 Order, p. 29.
[217] *Id.*

adopt Staff's adjustment based on the ELCC of the QF and the proxy plant.

3) Adopt Staff's proposed three-option methodology for the calculation of UPPCO's avoided energy costs, specifically, giving the QFs the choice of: (i) adopting energy prices based on the actual LMP, (ii) using the then-existing forecasted LMP price over the term of the contract, or (iii) accepting a proxy price based on the forecasted variable energy cost of a NGCC plant, along with an ICE adder applied to each method.
4) Adopt Staff's proposed limitation of the Standard Offer to QFs of 1 to 5 MW, with a 1 MW cap initially, to be revisited in the Company's next avoided cost filing.
5) Adopt ELPC's recommendation that a minimum 15-year Standard Offer contract term option be extended to QFs.
6) Adopt ELPC's recommendation to recognize that QFs may either sell the renewable energy credits to the Company or dispose of them at the QF's option.
7) Adopt Staff's recommendation set forth in its PURPA Report regarding other avoided costs – specifically, that the miscellaneous avoided costs or benefits provided by reduced transmission costs, line loss mitigation, hedging value, avoided emissions, and environmental compliance costs should be evaluated on a case-by-case basis for inclusion in the avoided cost rate, at the request of the QF.
8) Decline to adopt ELPC's recommendation that Staff be required to undertake a VOS analysis in the instant proceeding.

Any other matters that may have been raised by the parties to this case, but that have not been specifically addressed in this PFD, were found to be unnecessary for the resolution of the specific issues set forth by the Commission in the context of this proceeding.

MICHIGAN ADMINISTRATIVE HEARING SYSTEM
For the Michigan Public Service Commission

Suzanne D. Sonneborn

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Suzanne D. Sonneborn
Administrative Law Judge

ISSUED: July 5, 2017